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# UTILIZATION OF WASTE RENEWABLE FUELS IN BOILERS WITH MINIMIZATION OF POLLUTANT EMISSIONS

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# **TABLE OF CONTENTS**

<b>LIST OF FIGURES.....</b>	<b>5</b>
<b>LIST OF TABLES.....</b>	<b>8</b>
<b>LIST OF TABLES.....</b>	<b>8</b>
<b>ACKNOWLEDGEMENTS .....</b>	<b>9</b>
<b>ACKNOWLEDGEMENTS .....</b>	<b>9</b>
<b>ABSTRACT .....</b>	<b>10</b>
<b>EXECUTIVE SUMMARY .....</b>	<b>11</b>
California Biomass Resource Assessment .....	12
Laboratory Scale Gasification Experiments.....	13
Biomass Particle Gasification and Reburning Kinetics .....	13
Pilot Scale Cofiring/Reburning Tests and Modeling.....	14
Fouling/Slagging and Byproduct Emissions .....	15
Full Scale Conceptual Design .....	15
Economic Evaluation.....	15
Market Evaluation .....	16
Production Readiness Plan.....	17
<b>1.0 INTRODUCTION .....</b>	<b>23</b>
1.1 Purpose of Report.....	23
1.2 Purpose of Project .....	23
1.3 Project Goals.....	23
1.4 Actual Project Expenditures (PIER and Match Funds).....	24
1.5 Background.....	25
1.5.1 CCG Concept .....	25
1.5.2 Approach.....	25
<b>2.0 CONCLUSIONS AND RECOMMENDATIONS .....</b>	<b>31</b>
2.1 Meeting Technical Objectives .....	31
2.2 Meeting Economic Objectives.....	31
2.3 Commercialization Potential.....	31
2.4 Benefits to California .....	32
2.4.1 Environmental .....	32
2.4.2 Energy.....	32
2.4.3 Employment.....	33
<b>3.0 DISCUSSION .....</b>	<b>34</b>
3.1 Assessment of California Biomass Resources for Gasification.....	34
3.1.1 Biomass Waste Production, Availability, and Cost .....	34
3.1.2 Current Fuel Usage and Future Desires at Host-Site Biomass Boilers .....	35
3.1.3 Selection of Biomass Waste Fuel for Use in CCG Research Testing .....	36
3.2 Laboratory Scale Gasification Experiments and Modeling.....	48
3.2.1 Fluidized Bed Gasification Reactor.....	48

3.2.2	Experimental Procedures .....	48
3.2.3	Results and Discussion .....	49
3.2.4	Gasification Modeling .....	50
3.3	Kinetics of Biomass Particles Gasification / Reburning .....	61
3.3.1	Char Gasification Model.....	61
3.3.2	Experimental System and Testing Procedures.....	61
3.3.3	Results and Discussion .....	63
3.4	Pilot-Scale Cofiring / Reburning Stoker Simulation Tests Utilizing Gasified Biomass Fuels 70	
3.4.1	Experimental System.....	70
3.4.2	Experimental Testing.....	72
3.4.3	Results and Discussion .....	73
3.4.4	Summary and Conclusions .....	78
3.5	Fouling / Slagging and Byproduct Emissions.....	92
3.5.1	Slagging and Fouling Experimental System and Testing Procedures.....	92
3.5.2	Slagging and Fouling Experimental Results.....	93
3.5.3	By-Product Emissions Evaluation.....	93
3.6	Process and Kinetic Modeling .....	101
3.6.1	Modeling Procedure .....	101
3.6.2	Results and Discussion .....	102
3.7	Full Scale Conceptual Design.....	115
3.7.1	CCG General System Components and Arrangement .....	115
3.7.2	Boiler Descriptions.....	115
3.7.3	Conceptual Design.....	117
3.7.4	CCG Design Integration With Boilers.....	118
3.7.5	Injector Specifications .....	121
3.7.6	Thermal Performance Analysis.....	122
3.7.7	NO <sub>x</sub> Projections.....	124
3.7.8	Summary and Conclusions .....	126
3.8	CCG Economics Evaluation.....	146
3.8.1	Boiler and Gasifier Size and Performance.....	146
3.8.2	Gasifier Type.....	147
3.8.3	Capital Cost of CCG System Components .....	148
3.8.4	CCG Operating Costs .....	150
3.8.5	Economic Analysis Procedure .....	150
3.8.6	CCG Fuel Gas Cost and Cost of Electricity.....	151
3.8.7	Comparison of CCG NO <sub>x</sub> Control Costs with Current NO <sub>x</sub> Control Costs.....	152
3.9	Market Evaluation.....	166
3.9.1	State of the Industry: California Biomass Boilers.....	166
3.9.2	NO <sub>x</sub> Reduction .....	167
3.9.3	Alternative Fuels .....	168
3.10	Production Readiness .....	175
3.10.1	Commercialization .....	175
3.10.2	Implementation Plan.....	180
3.10.3	Conclusions .....	182
<b>REFERENCES .....</b>		<b>184</b>

## LIST OF FIGURES

Figure 1. A variant of the CCG technology: combination of direct combustion with reburning of waste gasification products. ....	18
Figure 2. NO <sub>x</sub> reduction (X-axis) in relation to biomass fuel-N at 20% reburning fuel heat input. ....	18
Figure 3. Cost of fuel gas (\$/MMBtu) with a 10-year repayment term at various capital costs (\$/kWe) and biomass fuel costs (\$/ton). ....	19
Figure 4. Effect of capital cost and fuel cost on the cost of electricity.....	19
Figure 5. NO <sub>x</sub> control cost effectiveness for CCG. ....	20
Figure 6. UC Davis fluidized bed reactor. ....	51
Figure 7. Typical temperature profiles through the reactor. ....	52
Figure 8. Ammonia content as a function of Fuel N. ....	53
Figure 9. Comparison between measured and calculated mass remaining profiles for selected biomass fuels particles burning in 8-mol % oxygen at nominally 1243 K. ....	65
Figure 10. Size and apparent density distributions of almond shell particles burning in 8-mol % oxygen at 1243 K. ....	66
Figure 11. Size and apparent density distributions of rice straw particles burning in 8-mol % oxygen at 1243 K. ....	66
Figure 12. Size and apparent density distributions of wood-W (whole tree chips) char particles burning in 8-mol % oxygen at 1243 K. ....	67
Figure 13. Size and apparent density distributions of walnut tree pruning (wood-P) char-particles burning in 8-mol % oxygen at 1243 K. ....	67
Figure 14. Size and apparent density distributions of sewage sludge particles burning in 8 mol-% oxygen at 1243 K. ....	68
Figure 15. A typical thermogram and temperature profile measured in the PTGA. Particles are in an inert (100% N <sub>2</sub> ) environment up to time = 3100 sec. After this time, they are exposed to an oxidizing environment. The thermogram shown is for almond shell char particles being exposed to 6 mol-% O <sub>2</sub> at 673 K. ....	68
Figure 16. Hybrid Fluidized Bed Gasifier (HFBG). ....	79
Figure 17. Solid Fuels Test Facility (SFTF). ....	80
Figure 18. Synthesis gas composition of various biomass fuels at SR= ~0.3.....	81
Figure 19. Almond shells gasification products. ....	81
Figure 20. Heating value of gasification products.....	82
Figure 21. Reburning performance of Liquid Petroleum Gas (LPG) at various NO <sub>i</sub> in SFTF. ....	82
Figure 22. Reburning performance of LPG and gasified biomass products at NO <sub>i</sub> = 300 ppmv..	83
Figure 23. Correlation for NO <sub>x</sub> reduction and fuel-N at 20% biomass syngas heat input.....	83
Figure 24. Reburning performance of gasified biomass products at NO <sub>i</sub> = 100 ppm. ....	84
Figure 25. Reburning performance of gasified MSS (NO <sub>i</sub> = 100 ppm). ....	84
Figure 26. Reburning performance of gasified MSS (NO <sub>i</sub> = 300 ppmv). ....	85
Figure 27. Almond shells reburning experimental data at 2151°F and 1827°F. ....	85
Figure 28. Impact of reburning fuel injection temperature on HFBG gasified MSS reburning performance (NO <sub>i</sub> =270 ppmv @ 0% O <sub>2</sub> ). ....	85
Figure 29. Advanced Reburning (AR) with almond shells syngas at high reburn temperature. ..	86

Figure 30. Advanced reburning (AR-Rich) with MSS syngas at high reburning fuel injection temperature (reburn fuel at 2100°F, urea/sodium at 1900°F and OFA at 1680°F, NO <sub>i</sub> = 280 ppmv, and urea and sodium injected into the rich zone).....	86
Figure 31. Advanced reburning with MSS syngas at low reburn fuel injection temperature (reburn fuel at 1840°F, urea/sodium injected at 1680°F with OFA).....	87
Figure 32. Advanced reburning with MSS syngas (reburning fuel at 2100°F, OFA at 1680°F, urea/sodium at 1900°F, NO <sub>i</sub> = 280 ppmv @ 0% O <sub>2</sub> ).....	87
Figure 33. Impact of syngas cofiring on NO emissions. ....	88
Figure 34. NO emissions with gasified municipal sewage sludge co-firing.....	88
Figure 35. Comparison Between Biomass Syngas Cofiring and Reburning ( <i>Reburn/Cofire at 20% for waste paper and 14% for other fuels</i> ) .....	89
Figure 36. Relative fouling factors for woodchips baseline and woodchips firing plus 10% cofiring of Wood “P” syngas.....	96
Figure 37. Relative heat absorptions for woodchips baseline and woodchips firing plus 10% cofiring of Wood “P” syngas.....	97
Figure 38. Relative fouling factors for woodchips baseline and woodchips firing plus 10% cofiring of municipal sewage sludge syngas. ....	98
Figure 39. Relative heat absorptions for woodchips baseline and woodchips firing plus 10% cofiring of municipal sewage sludge syngas. ....	99
Figure 40. Modeling (lines) and experimental results for natural gas reburning (NO <sub>i</sub> = 600 ppm). ....	108
Figure 41. Experimental data (symbols) and modeling prediction (lines) for LPG reburning. ..	108
Figure 42. Comparison between modeling predictions and experimental data for reburning with Almond Shells gasification products. ....	108
Figure 43. Correlations at NO <sub>i</sub> = 300 ppm between NO <sub>x</sub> reduction and (1) biomass fuel-N content at 20% reburning fuel heat input (solid line and open symbols) and (2) between fuel-N and sodium content of biomass at 8% reburning fuel heat input (dashed line and filled symbols). Symbols represent: squares – Rice Straw, triangular – Wood P, circles – Waste Paper, crosses – Wood W, and rhombuses – Almond Shells. ....	109
Figure 44. Comparison between modeling and experimental results. Squares – Almond Shells, triangles – Waste Paper. Open symbols – NO <sub>i</sub> = 300 ppm, filled symbols – NO <sub>i</sub> = 100 ppm. ....	110
Figure 45. Comparison between modeling predictions and experimental data. Squares - LPG at NO <sub>i</sub> = 300 ppm, triangular – Wood P at NO <sub>i</sub> = 300 ppm, circles – LPG at NO <sub>i</sub> = 100 ppm. ....	110
Figure 46. Experimental and modeling results for sewage sludge (reburn T = 2150°F).....	110
Figure 47. Predicted effects of Na and NH <sub>3</sub> on NO <sub>x</sub> reduction in Almond Shells reburning at 2150°F..	111
Figure 48. Predicted temperature dependence of the efficiency of NO <sub>x</sub> reduction in reburning with Almond Shells gasification products. ....	111
Figure 49. Impacts of fuel-N content on NO <sub>x</sub> reduction performance. ....	111
Figure 50. Effect of NH <sub>3</sub> co-injection with gasification products of Almond Shells on NO <sub>x</sub> reduction at 1840°F injection temperature. ....	112
Figure 51. AR-Rich. Effect of urea and Na <sub>2</sub> CO <sub>3</sub> injection into the reburning zone on NO <sub>x</sub> reduction at 8% gasified MSS reburning (T <sub>RF</sub> = 2150°F, Urea/Na at 1900°F, T <sub>OFA</sub> = 1680°F, NO <sub>i</sub> = 280 ppm, N <sub>2</sub> atomizer, NSR =1.5, [Na] =100 ppm).....	113

Figure 52. AR-Rich. Effect of urea and $\text{Na}_2\text{CO}_3$ injection into reburning zone on $\text{NO}_x$ reduction at 10% reburning heat input for almond shells.....	113
Figure 53. AR-Lean. Effect of urea and $\text{Na}_2\text{CO}_3$ co-injection with OFA on $\text{NO}_x$ reduction at 7% reburning ( $T_{\text{RF}}=1840^\circ\text{F}$ , $T_{\text{OFA}}=1680^\circ\text{F}$ , $\text{NSR}=1.5$ , $\text{Na}=100$ ppm, $\text{N}_2$ atomizer, Urea & Na co-injected with OFA, $\text{NO}_i = 280$ ppm).....	114
Figure 54. AR-Lean. Effect of urea and $\text{Na}_2\text{CO}_3$ co-injection with OFA on $\text{NO}_x$ reduction at 10% reburning heat input for almond shells. ....	114
Figure 55. Spreader Stoker Traveling Grate at Wheelabrator Shasta, Zurn boiler. ....	127
Figure 56. Suspension-Fired Rice Hull Boiler at Wadham Energy. ....	128
Figure 57. Circulating Fluidized Bed at Woodland Biomass. ....	129
Figure 58. Application of reburning technologies to Wheelabrator Shasta boiler.....	130
Figure 59. Process flow diagram applying conventional reburning to Wheelabrator Shasta boiler. ....	131
Figure 60. Process flow diagram applying low-T reburning to Wheelabrator Shasta boiler.....	132
Figure 61. Application of reburning to the Wadham Energy boiler.....	133
Figure 62. Process flow diagram applying conventional reburning to Wadham Energy boiler. ....	134
Figure 63. Process flow diagram applying low-T reburning to Wadham Energy boiler.....	135
Figure 64. Application of low-T reburning to the Woodland CFB boiler. ....	136
Figure 65. Process flow diagram applying low-T reburning to Woodland boiler. ....	137
Figure 66. Predicted bulk gas furnace temperatures for full load baseline and conventional reburning conditions. ....	138
Figure 67. Predicted bulk furnace gas furnace temperatures for full load baseline and low-T reburning conditions. ....	139
Figure 68. Fixed Updraft Gasifier (PrimeEnergy, Inc.).....	156
Figure 69. Bubbling Fluidized Bed Gasifier (Energy Products of Idaho).....	156
Figure 70. Circulating Fluidized Bed Gasifier (Foster Wheeler Energia, Oy) .....	157
Figure 71. Dual Circulating Fluidized Bed Gasifier (Future Energy Resources Company) .....	157
Figure 72. Biomass Fuel Flow .....	158
Figure 73. Biomass Fuel System.....	158
Figure 74. Effect of repayment term (y) and cost of capital and non-fuel O&M (\$/kWe) on cost of fuel gas from gasifier during term of capital repayment. Does not include biomass fuel cost. ....	159
Figure 75. Effect of biomass fuel cost (\$/ton) on cost of fuel gas from gasifier. Does not include capital or non-fuel O&M costs. ....	159
Figure 76. Cost of fuel gas (\$/MMBtu) with a 10-year repayment term at various capital costs (\$/kWe) and biomass fuel costs (\$/ton). ....	160
Figure 77. Effect of CCG capital and repayment terms on the cost of electricity. ....	160
Figure 78. Effect of cost of biomass fuel (\$/ton) on cost of electricity from gasifier. Does not include capital or non-fuel O&M costs.....	161
Figure 79. Effect of capital cost and fuel cost on the cost of electricity.....	161
Figure 80. $\text{NO}_x$ control cost effectiveness for CCG. ....	162

## LIST OF TABLES

Table 1. Waste biomass resource assessment for California. ....	21
Table 2. CCG for biomass boiler host sites. ....	22
Table 3. Availability, gross production, and cost of biomass waste resources. ....	39
Table 4. Waste cost assumptions. ....	45
Table 5. Summary of waste resources. ....	46
Table 6. Waste biomass resource assessment for California. ....	47
Table 7. Fuel sampling and analysis. ....	54
Table 8. Sampling and measurements for fuel screening experiments. ....	55
Table 9. Compositions and ash fusion temperatures of test fuels. ....	57
Table 10. Average operating parameters. ....	58
Table 11. Producer gas (% vol.) ....	58
Table 12. Gas phase alkali, chlorine, and ammonia concentrations. ....	59
Table 13. Elements balance / closures. ....	60
Table 14. Reactivities of chars burning in 8-mol % oxygen at 1243 K. ....	69
Table 15. Test matrix for gasification and reburning / cofiring tests. ....	90
Table 16. Operating conditions for the HFBG. ....	91
Table 17. Operating conditions for the SFTF. ....	91
Table 18. Deposit characteristics for slagging and fouling experiments. ....	100
Table 19. Fuel composition. ....	140
Table 20. Conventional reburn system design basis. ....	140
Table 21. Low-temperature reburn system design basis. ....	141
Table 22. Preliminary conventional reburning injector specifications. ....	141
Table 23. Preliminary low-T reburning injector specifications. ....	142
Table 24. Comparison of baseline and conventional reburning performance at full load. ....	143
Table 25. Comparison of baseline and low-T reburning performance at full load. ....	144
Table 26. Projected NO <sub>x</sub> reduction at full load. ....	145
Table 27. Operating assumptions: performance of biomass plants. ....	163
Table 28. Gasifier size and performance. ....	163
Table 29. Capital costs (\$1,000) of fuel systems for 200 TPD (100 MMBtu/h). ....	163
Table 30. Capital costs (\$1,000) of gasifiers. ....	164
Table 31. Gasification system costs (\$ 1,000) for 100 MMBtu/h (200 tpd). ....	164
Table 32. Assumptions for the economics analysis used in CCG capital cost estimates. ....	165
Table 33. Assumptions for the economics analysis. ....	165
Table 34. Nitrogen in biomass fuels. ....	165
Table 35. Status of biomass plants in California. ....	173
Table 36. Boiler type and capacity by PG&E and SCE contract July 2001. ....	173
Table 37. Costs to produce electricity from biomass in California. ....	174
Table 38. NO <sub>x</sub> Emissions limits in California biomass plants. ....	174
Table 39. Commercial gasifier suppliers. ....	183

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## Abstract

A Close-Coupled Gasification (CCG) technology, which utilizes low-grade biomass fuels and reduces NO<sub>x</sub> emissions from existing biomass boilers, has been successfully demonstrated at pilot scale without causing boiler slagging and fouling or increased pollutant emissions. The CCG technology involves the synergistic combination of biomass gasification and syngas cofiring or reburning for NO<sub>x</sub> control. An assessment of California biomass resources cost and availability identified six fuels that are readily available and at relatively low cost for testing in the Phase I CCG project. The six waste fuels, including rice straw, almond shells, tree chips, agricultural pruning, non-recyclable waste paper, and municipal sewage sludge, were selected for CCG demonstration testing at lab- and pilot-scale facilities. All fuels were shown to produce high quality syngas in laboratory gasifier studies. In pilot scale studies, NO<sub>x</sub> reductions up to 65% were demonstrated using “low-temperature” reburning, and up to 90% NO<sub>x</sub> reductions were achieved using “advanced” reburning. No impact on boiler slagging or fouling was observed. Based on operating conditions and data gathered during pilot scale tests, no impact on boiler metal or organic emissions was predicted. Full-scale conceptual designs were developed for three potential host site biomass boilers; no “showstoppers” were identified and no adverse impact on boiler thermal performance was predicted. An economic evaluation of the CCG technology was performed and results suggest that for low-cost fuels [particularly no-cost or negative-cost (with tipping fees) fuels], the CCG NO<sub>x</sub> control cost effectiveness is 25% less than that of conventional NO<sub>x</sub> control; and the cost of fuel gas and electricity from the CCG is comparable to that for existing biomass boilers. Full-scale demonstration is critical for progress in the CCG commercialization effort. All components of the CCG technology are readily commercially available and well demonstrated. Potential commercialization partners of CCG components are prepared and promoting the technology in anticipation of full-scale demonstration in a Phase II project.

## Executive Summary

A Close-Coupled Gasification (CCG) technology, which utilizes low-grade biomass fuels (such as those with high alkali and/or nitrogen content) and reduces NO<sub>x</sub> emissions from existing biomass boilers, has been successfully demonstrated at pilot scale without causing boiler slagging and fouling or increased pollutant emissions. The CCG technology involves the synergistic combination of biomass gasification and cofiring or reburning (where low-grade biomass fuel is gasified, and the gasifier syngas is used as a fuel in an existing boiler in a gas cofiring or “reburning” arrangement, as shown in Figure 1). The CCG concept focuses on bringing renewable energy, energy supply reliability, energy price stability, and protection of the environment to the California marketplace.

The prime contractor leading the CCG technology development effort is GE Energy and Environmental Research Corp. (GE EER). The GE EER team includes subcontractors (University of California at Davis, Stanford University, and T.R Miles, Technical Consultants, Inc.) and additional project participants who provide assistance to the CCG program through review of results and participation in program review meetings. Additional project participants include representatives from Electric Power Research Institute (EPRI), two gasifier developers (Energy Products of Idaho, EPI, and Battelle/FERCO), and three California biomass boiler operators (Wadham Energy, Wheelabrator Shasta, and Woodland Biomass).

This project represents Phase I of a four-phase CCG technology development and commercialization plan. To evaluate the overall characteristics of the CCG concept and demonstrate its feasibility, a research and development program (Phase I) funded by California Energy Commission began in late 1999. The Phase I program activities include:

- Conducting a California biomass resource assessment to select biomass fuels for the experimental program.
- Identifying most promising feedstocks via laboratory-scale gasification screening tests.
- Optimizing cofiring and reburning performance of gasified products through modeling and testing in a pilot-scale combustor simulating a stoker-boiler.
- Quantifying changes in the furnace slagging and convective pass fouling characteristics, if any, under cofiring and reburning conditions with gasified waste fuels.

- Conducting a full-scale conceptual design to three potential existing host-site California biomass boilers.
- Performing economic and market evaluation studies as well as drafting a production readiness plan.

Key information, main results and conclusions from the Phase I program are summarized below per major task.

## ***California Biomass Resource Assessment***

In the first task of the Phase I program, a resource assessment study was conducted to determine the availability, cost, and composition of biomass resources in California that have the potential for use in the CCG application. Table 1 summarizes, for various biomass categories, total gross generation rate, the amount that is estimated to be available (not currently being utilized), non-delivered cost, and major advantages and disadvantages. Based on this review, and discussions with the operators of the three existing California biomass boiler power plants that are targeted as potential host sites for the full-scale integration and demonstration of the CCG technology, six biomass fuel types were selected for use in the Phase I CCG program:

- *Whole Tree Chips* – Projected to be available in large quantities at low cost due to forest thinning activities for fire prevention and forest health. Used extensively in two of the potential host site California biomass boilers.
- *Orchard Tree Pruning* – Available at low cost due to restrictions on open burning.
- *Non-Recyclable Paper* – Available at low cost due to increasing landfill costs, decreasing landfill availability, and state mandates on a 25% reduction of municipal solid waste that is sent to landfills.
- *Almond Shells* – Available at low cost.
- *Municipal Sewage Sludge* – Potentially available at a negative cost (tipping fee received for accepting sludge). Available due to increasing restrictions on current use as land amendment/fertilizer.
- *Rice Straw* – Potentially available as a result of restrictions on open burning. Tax credits and subsidies may be given for its use. Current usage in existing biomass boilers is limited by the high alkali content that causes boiler operational problems (boiler tube slagging and fouling).

## ***Laboratory Scale Gasification Experiments***

Gasification experiments were conducted at the University of California (UC Davis) utilizing a lab-scale fluidized bed apparatus in which the six selected biomass fuel samples were tested. The objectives of the testing were to determine the gasification characteristics of each of the biomass fuels, including syngas composition, speciation and fate of alkalis and nitrogen compounds, fluidized bed agglomeration, and fouling deposition of the syngas.

All biomass fuels were readily gasified, and produced a high quality, robust syngas with significant heating value (4-20% H<sub>2</sub>, 10-22% CO, and 4-8% CH<sub>4</sub>). The ammonia content of the syngas was directly correlated to the fuel nitrogen content. The level of chlorine and potassium in the syngas was not strongly related to the level in the feed; most was condensed out of the syngas prior to the syngas sampling location. Bed agglomeration using standard alumina-silicate bed materials was not a problem for all fuels except rice straw. Gasification of rice straw required the addition of magnesium oxide to prevent bed agglomeration.

## ***Biomass Particle Gasification and Reburning Kinetics***

Further laboratory scale testing was conducted at Stanford University to evaluate the biomass char oxidation process and biomass devolatilization rates under simulated reburning conditions for each of the six-biomass fuels. A char oxidation model was developed based on the testing results.

All biomass fuels showed rapid and substantial mass losses during high temperature devolatilization. All biomass chars had very high levels of conversion (low levels of carbon, mostly ash constituents). Both particle “fragmentation” and “swelling” were observed during the devolatilization process, which significantly alter the size distribution of the char particles compared with that of the original biomass particle feed. Specifically, particle size decreases and particle density increases as the particle residence time increases.

Biomass chars were shown to be highly reactive (much more reactive than coal chars). It is concluded that the higher volatile contents of the original fuel, the higher the reactivity of the char that is produced. Char reactivity was observed to decrease as it burns at high temperature due to thermal annealing.

## ***Pilot Scale Cofiring/Reburning Tests and Modeling***

Reburning and cofiring tests were conducted at the GE Energy and Environmental Research Corp. (GE EER) test site facility in Irvine, California, using a pilot-scale boiler simulator fired with gasified biomass fuels. Tests were conducted to evaluate reburning NO<sub>x</sub> control performance. Concurrently, kinetic and process modeling was performed to assist in determining biomass syngas reburning conditions for optimum NO<sub>x</sub> reduction.

Basic reburning tests were conducted using a syngas reburning injection temperature of 2,150°F (“conventional” reburning) with boiler initial NO<sub>x</sub> levels of about 300 ppmv. Overfire air was added in the boiler at about 1,850°F, producing a reburning zone residence time of about 800 ns. Reburning NO<sub>x</sub> reduction performance increases with increasing reburning heat input up to about 15% heat input. However, for all biomass fuels, except low nitrogen containing waste paper, reburning performance decreases at a heat input greater than 15%. As predicted by modeling and verified with experimental data (Figure 2), reburning NO<sub>x</sub> reduction performance was shown to be a very strong function of the biomass fuel nitrogen content and injection temperature. Syngas nitrogen species such as ammonia and hydrogen cyanide form NO<sub>x</sub> during overfire air reburning.

Further optimized basic reburning tests were conducted. As predicted by modeling, NO<sub>x</sub> reductions of up to 65% were achieved for high nitrogen fuels by lowering the reburning injection temperature to 1,830°F (“low-temperature” reburning), and with reburn fuel heat input of about 5-10%. Alternatively, improved NO<sub>x</sub> reduction for low nitrogen fuels was achieved by increasing the injection temperature (“conventional” reburning) and amount of reburn fuel.

Advanced reburning tests were performed using the addition of urea and sodium promoters. Up to 90% NO<sub>x</sub> control was achieved using advanced reburning.

Cofiring tests showed that NO<sub>x</sub> emissions increase as biomass syngas heat input is increased, particularly for high nitrogen biomass fuels.

Experimental and modeling results confirm that the CCG technology shows a promise in reducing NO<sub>x</sub> emissions from biomass boilers while using low-cost waste biomass. The agreement of the experimental results with the model shows that the model can predict the system performance and can be used to develop a design basis for application of the technology to a specific boiler.

## ***Fouling/Slagging and Byproduct Emissions***

Gasification and subsequent cofiring/reburning tests conducted using the pilot-scale GE facility in Irvine indicated that direct cofiring of raw, unclean biomass syngas did not significantly affect the slagging or fouling characteristics of the boiler. Deposits were generally light and easy to remove. Trace organic emissions are expected to decrease as a result of the cofiring of biomass gasifier syngas. Additionally, cofiring of biomass gasifier syngas is not expected to adversely impact boiler trace metals emissions because: (1) most biomass fuels have low trace metals content, and (2) metals that are present are readily controlled through conventional boiler gas cleanup operations.

## ***Full Scale Conceptual Design***

Preliminary designs were developed for the integration of a CCG system into the three California biomass boilers that are potential full-scale demonstration host-sites. This included detailed specifications of biomass reburning fuel-firing rates, reburning fuel injector design and locations, and overfire air requirements. No “show-stoppers” were identified. Heat transfer modeling results suggest that the addition of biomass syngas reburning will not significantly impact the boiler thermal performance. Carbon in ash is projected to drop slightly and boiler heat loss efficiency is projected to drop by < 1%.

## ***Economic Evaluation***

An economic evaluation was performed for the application of the CCG technology to California biomass boilers. Table 2 summarizes estimated CCG capital cost investment (CCI) for application to each of the three potential California host-site biomass boilers (Wadham Energy, Wheelabrator Shasta, and Woodland Biomass). Based on recent estimates obtained from industry experts, the CCG CCI is expected to range from \$900 – 1,300 / kWe, depending on the gasifier size and CCG fuel handling requirements.

Figure 3 shows the CCG fuel gas cost (\$/MMBtu of syngas) as a function of CCG CCI, and CCG biomass opportunity fuel cost (\$/ton) assuming a 10-year repayment term on the CCI. Common woody biomass fuel costs are in the \$1.00 – 2.00 / MMBtu range (\$15 – 30 / ton fuel). Thus, a CCG fuel gas production target of \$1.00/MMBtu or less is desirable. CCG systems for the Wadham and Woodland boilers (with a CCI of \$1,300/kWe) are projected to achieve a fuel gas cost of \$2.75/MMBtu for biomass fuel at \$10/ton, and a fuel gas cost of \$1.00/MMBtu with

CCG biomass fuel at a cost of -\$10/ton (i.e., fuel at a negative, tipping fee cost of \$10/ton). No-cost (or tipping fee, negative cost) biomass fuel may include urban wastes (such as waste paper or plastics), sewage sludge, potentially subsidized fuels such as rice straw, and low value agricultural residues such as shells and pits. For the Wheelabrator boiler (with a CCI of \$900/kWe), a fuel gas cost of \$1.00/MMBtu is achieved for a CCG biomass fuel of -\$5/ton.

Figure 4 shows the estimated CCG cost of electricity (not including boiler operational costs) as a function of CCG CCI, and CCG biomass opportunity fuel cost (\$/ton) assuming a 10-year repayment term. For a CCG biomass fuel cost of \$10/ton (\$1.00/MMBtu) at the host sites, the CCG cost of electricity is between about \$0.04 – 0.05 / kWe. For a no-cost biomass fuel, the CCG cost of electricity is about \$0.023-0.033/kWe. For comparison, for a typical biomass boiler, electricity is produced at about \$0.018/kWe with biomass fuel at a cost of \$1.00/MMBtu.

Figure 5 shows estimated CCG NO<sub>x</sub> control cost effectiveness as a function of CCG capital cost investment and CCG fuel cost. For low cost fuels, the CCG NO<sub>x</sub> cost effectiveness compares very favorably with that of SNCR; SNCR NO<sub>x</sub> control cost is estimated at about \$800 to \$1,000 / ton NO<sub>x</sub> reduced. For the Wheelabrator CCG (with a CCI of about \$900/kWe) and a CCG biomass fuel that is \$12/ton cheaper than the standard main boiler fuel, the CCG NO<sub>x</sub> control effectiveness is \$600/ton or about 25% less than SNCR.

## ***Market Evaluation***

The CCG technology has a number of attractive features for application to existing California biomass boilers, including:

- Reduced fuel cost:
  - Use of increased amounts of lower cost, high alkali slagging fuels such as rice straw, rice hulls, nutshells, and fruit pits.
  - Use of biomass “wastes” that can have negative (tipping disposal fee) costs, including waste paper, urban wood wastes, and yard wastes.
- Reduced NO<sub>x</sub> emissions:
  - Valuable to existing boilers which would like to increase the capacity of existing plants, change/add fuels, or which under future regulations will be required to reduce NO<sub>x</sub> emissions.

- Reduce or eliminate current NO<sub>x</sub> control methods, such as SNCR or flue gas recirculation or feed nitrogen control.

Biomass boilers and waste disposal companies are the likely purchasers of CCG systems. The CCG technology is readily suited for stoker and cell-fired boilers, which can have high NO<sub>x</sub> and which tend to be limited in the amount of high alkali containing biomass that they can fire.

The key to commercialization of the CCG technology is the demand for biomass energy, which is very unstable, and is currently considered low. Factors that might increase biomass energy demand include:

- Incentives, such as tax subsidies, for disposal of biomass waste residues in energy plants.
- Incentives or regulations for coal facilities to cofire biomass.
- Increased NO<sub>x</sub> regulations for existing biomass plants.
- Incentives to install gasifiers, such as a producer gas tax credit.

The additional key to commercialization is the demonstration of the CCG at a full-scale biomass boiler.

There are about 26 operating and 17 idled biomass plants in California with capacities of 550 MW and 217 MW respectively. This represents a substantial market for more effective and efficient use of alternative fuels for power and cogeneration applications. The development of the CCG technology continues to proceed along a path designed to meet the needs of the market for both cost-effective and environmental approaches to alternative/renewable fuel utilization. Both the economic and market analyses confirm the viability of the CCG technology.

### ***Production Readiness Plan***

All components of the CCG concept are readily commercially available and well demonstrated. Gasifier suppliers currently have a very strong interest in providing systems for the CCG concept. Potential commercialization partners are prepared and promoting the technology in anticipation of full-scale demonstration.

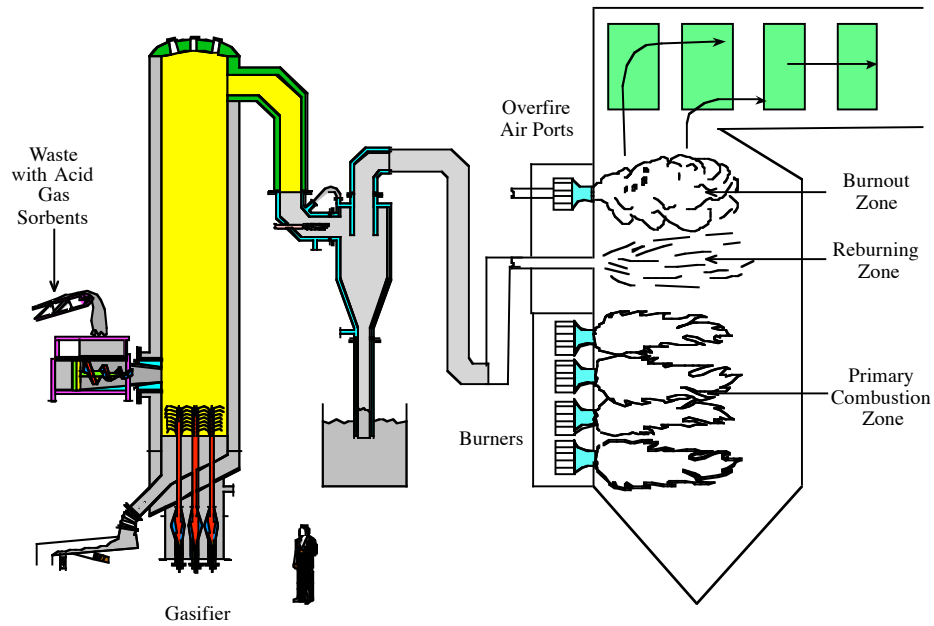


Figure 1. A variant of the CCG technology: combination of direct combustion with reburning of waste gasification products.

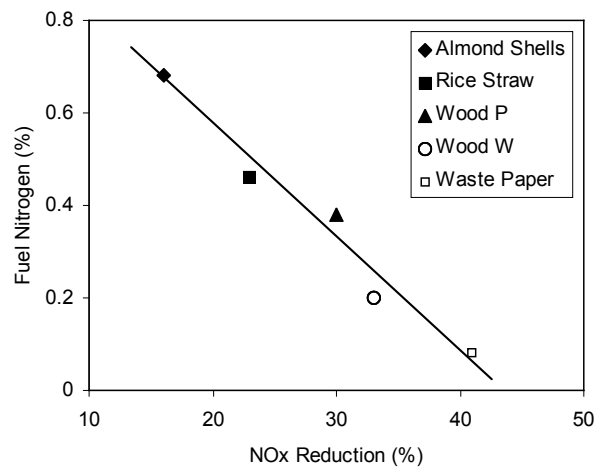


Figure 2. NOx reduction (X-axis) in relation to biomass fuel-N at 20% reburning fuel heat input.

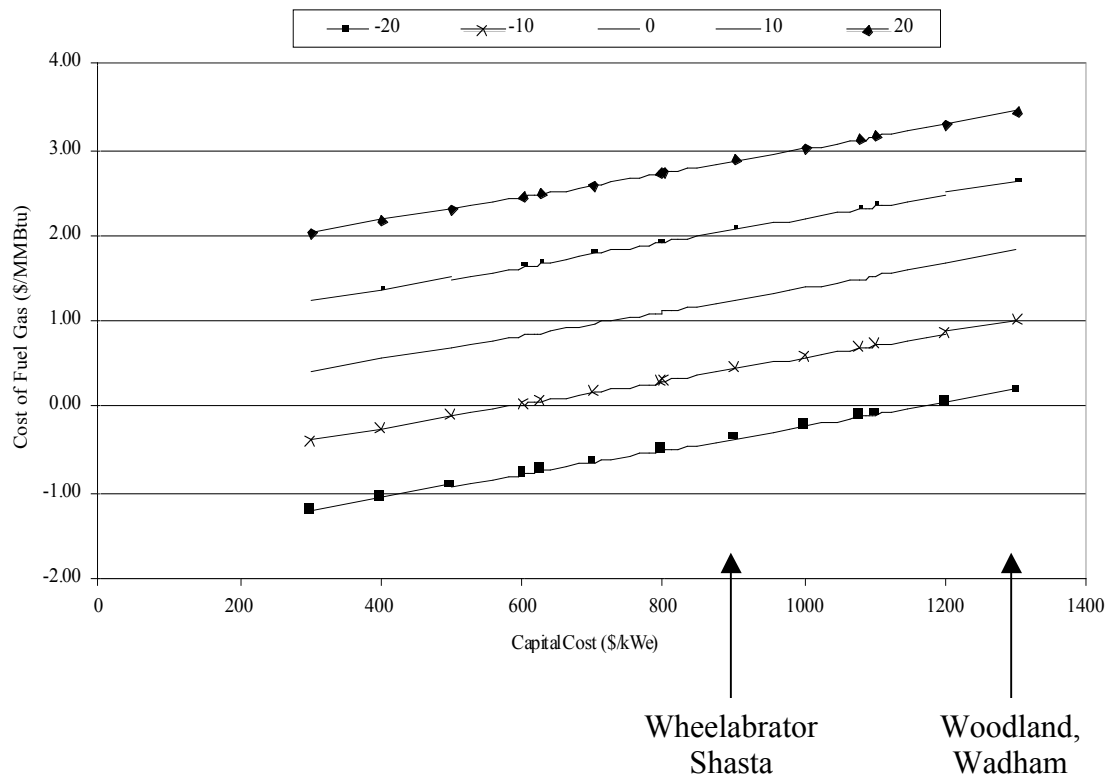


Figure 3. Cost of fuel gas (\$/MMBtu) with a 10-year repayment term at various capital costs (\$/kWe) and biomass fuel costs (\$/ton).

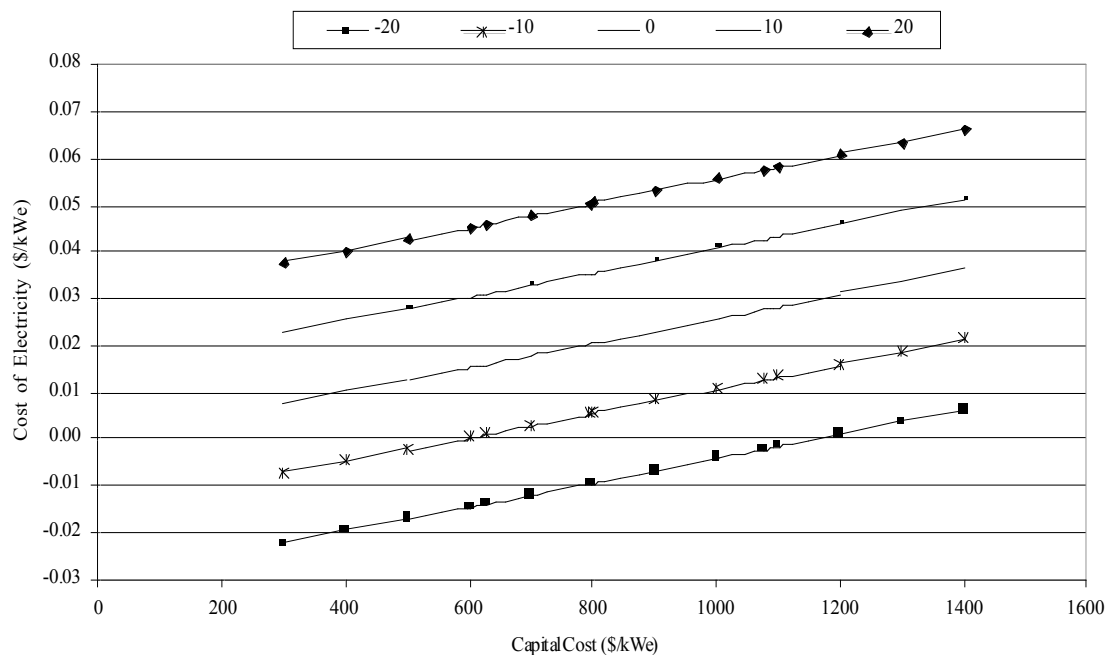


Figure 4. Effect of capital cost and fuel cost on the cost of electricity.

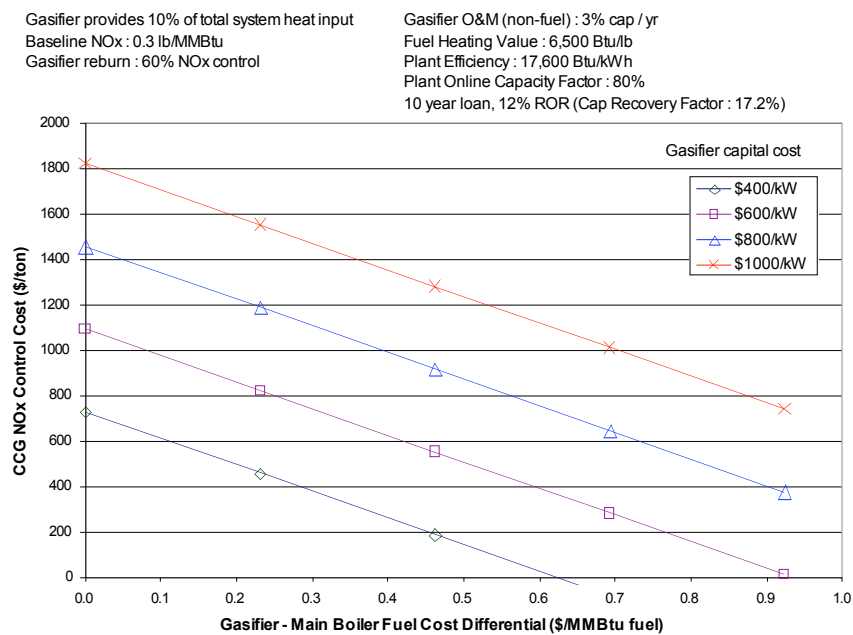


Figure 5. NOx control cost effectiveness for CCG.

Table 1. Waste biomass resource assessment for California.

<i>Waste Stream</i>	<i>Cost, Non-delivered (\$/BDT)</i>	<i>Quantity (Million BDT/yr)</i>		<i>Advantages</i>	<i>Disadvantages</i>
		Gross	Availability		
Wood mill waste	> 20	5.5	0	Clean fuel	Little available. High demand. Plywood, particleboard, landscaping material, fuel.
Forest slash	> 20	4.5	2.5	Fire prevention	Inconsistent, uncertain generation, availability, sustainability. Difficult collection.
Forest thinning	> 25	3.8	1.9		
Chaparral	> 25	7.7	0.8	Fire prevention, suburban growth	Very uncertain future collection.
Urban wood	> 30	3.2	0.7	Good fuel. CA MSW 50% reduction goal	Demand for particleboard, fuel. Separation and recovery needs.
Urban yard	> 30	3.9	1.2	Existing supply. CA MSW 50% reduction goal	Value for landscape material, landfill cover, and composting. Separation and recovery needs.
Non-recyclable waste paper	-30 to >20	13	2.5	Existing supply. CA MSW 50% reduction goal	Facility permitting. Recovery of low value mixed streams needed.
Sewage sludge	-30 to 0	0.7	0.6	Pressure on use as land treatment	Facility permitting.
Field crop straw and stalks	15 to 45	5.1	2.8	Potential supply. Rice: 15 \$/ton CA subsidy.	Slagging fuel. Rice: Open burning phase out in Sacramento Valley. Plowed under, problems? Others: Plowed under, more limited incentive
Woody agricultural wastes (fruit and nuts)	10	2	1.4	Existing supply for pruning. 10 \$/ton CA subsidy. Open burn reduction potential for nuts.	Fruit crop use as soil mulch incorporation. Nuts open burning. Collection difficulty. Clearings currently used.
Fruit pits, nut shells	10	1	0.5	Existing supply. Almond and walnut shells, fruit and olive pits	High N, P, K, Na. Small amounts.
Livestock manure	0 to 10	12		Available in confined dry feedlots. Focus on manure handling and treatment.	Much used as fertilizer and collected wet. Poultry litter not available.

Table 2. CCG for biomass boiler host sites.

Specifications	Units	Biomass Boiler		
		Wadham	Woodland	Wheelabrator Shasta
Boiler Size	MWe	30	28	54
Gasifier Heat rate	Btu/kWhe	18,526	18,526	18,526
Gasifier Size	MWe	3	2.8	5.4
	MMBtu/hr thermal	55.6	51.9	100.0
Gasifier Cost				
Capital Investment	\$/kWe	1,300	1,300	900

## **1.0 Introduction**

### **1.1 Purpose of Report**

This is the final report of the Phase I program for development and demonstration of a Close-Coupled Gasification (CCG) system. The primary benefit from the CCG technology is to produce electricity from biomass boilers using under-utilized California biomass waste fuels, while reducing NO<sub>x</sub> emissions.

### **1.2 Purpose of Project**

California has a number of under-utilized, lower quality, biomass waste streams which require mitigation including:

- *Forest management* – Forest thinning from overgrown forests. California forests are overgrown and in need of thinning to assist in maintaining forest health and preventing wildfires.
- *Landfill capacity* – Wood and paper from municipal solid waste. California landfills are filling up and landfill disposal costs are rising.
- *Open burning* – Agricultural and forest residues. Open burning of agricultural and forest residues is being restricted due to air quality concerns for NO<sub>x</sub>, ozone, and fine particles.
- *Biomass energy industry* – The California biomass energy industry continues to shrink, freeing up additional biomass streams.

At the same time, California is in need of: (1) energy supply reliability and price stability, and (2) electricity production sources that have low NO<sub>x</sub> emissions due to non-compliance with NO<sub>x</sub> and ozone regulations for many parts of California.

The CCG technology is designed to address these conflicting requirements; specifically, to use low quality under-utilized biomass (a renewable energy source) to produce cost effective electricity and reduce NO<sub>x</sub> emissions.

### **1.3 Project Goals**

The overall goal of this project is to demonstrate the technical and economic feasibility of the CCG concept and to develop conceptual designs for applications of the CCG technology to existing full-scale California biomass power plants.

This project is Phase I of a four-phase CCG technology development and commercialization plan. Phases II and III would be to design, retrofit, and operate a CCG demonstration facility at an existing host site California biomass boiler. Phase IV would be to commercialize the technology in California, domestically, and internationally.

This project supports the PIER program objective of reducing environmental risks and costs of California's electricity supply by developing a lower-cost method for existing biomass power plants to control NO<sub>x</sub> and other pollutant emissions. The project also contributes to the PIER program objective of maximizing a "market connection" for the project's research results. Specifically, three California biomass power corporations, who are potential partners in the full-scale CCG technology demonstration, are participating in the project's design and economic studies to determine if the technology will provide economic and operational benefits to their units.

The overall technical objective of this project is to develop and optimize the CCG process, which converts biomass/waste into gaseous fuel for use as supplementary fuel and NO<sub>x</sub> control in California biomass boilers. Specific technical goals of the project include demonstrating at pilot scale the ability of the CCG to:

- Produce 10-30% of gaseous fuel (by heat input) for a 25 MW biomass boiler.
- Reduce NO<sub>x</sub> emissions up to 65% in basic reburning and up to 90% in advanced reburning (AR).
- Comply with all other California emissions standards.

The overall economic objective of this project is to develop an economic process for converting biomass/waste into gaseous fuel to be used as supplementary cofiring/reburning fuel and NO<sub>x</sub> control in California biomass boilers. The specific economic goal of the project include demonstrating the ability of the CCG to:

- Reduce NO<sub>x</sub> control costs by at least 20% compared to the costs of existing NO<sub>x</sub> control methods used by biomass boilers owned by Wheelabrator Shasta/Hudson Energy Company, Woodland Biomass, and Wadham Energy.

#### **1.4 Actual Project Expenditures (PIER and Match Funds)**

The total PIER fund expenditure on this project (excluding the interagency agreement with UC Davis fund) is \$753,679 and the total match funds expenditure is \$553,661.

## **1.5 Background**

### **1.5.1 CCG Concept**

The Close-Coupled Gasification (CCG) concept is an innovative synergistic combustion of two well-demonstrated technologies – gasification and reburning. The integration provides the dual advantage of utilizing low-cost opportunity biomass waste streams in existing California boiler power plants, while at the same time reducing NO<sub>x</sub> emissions.

### **1.5.2 Approach**

The Phase I CCG technology development, demonstration, and design is accomplished through work in ten interrelated task areas:

Task 1	Assessment of California Waste and Biomass Resources for Gasification
Task 2	Laboratory Scale Gasification Screening Experiments
Task 3	Kinetics of Biomass and Waste Particles Gasification/Reburning
Tasks 4/5	Pilot Scale Cofiring/Reburning Simulation Tests
Task 6	Evaluation of Slagging, Fouling, and Byproduct Emissions
Task 7	Process Modeling
Task 8	Design Methodology/Application
Task 9	Economic and Market Analyses
Task 10	Technology Transfer

#### ***Task 1 – Assessment of California Waste and Biomass Resources for Gasification***

The purpose of this task is to determine the availability and costs of collecting and transporting biomass/waste resources to selected California biomass power plants, so that these plants will have sustainable fuel supplies for the CCG technology. Biomass categories include:

- Agricultural residues (field and seed crop residues, fruit and nut crop residues, livestock manure).
- Forest thinning and residues (lumber mill waste, forest slash).
- Food processing residues (nut shells, rice hulls, fruit pits).
- Urban waste (yard waste, demolition materials, municipal solid waste, post-consumer waste, municipal sewage sludge, chemical and refinery waste).

For each category, information is collected on the physical and chemical characteristics of biomass/waste resources and the total production amounts. Next, potentially available amounts

within each resource category are estimated by region, considering feedstock processing requirements, sustainability issues, gasifier technology processing requirements, the extent to which the resource is concentrated by region, alternative uses for the feedstock, known environmental limitations in feedstock acquisition, and other constraints. Costs are estimated for producing, processing, handling and delivering biomass/waste resources to three potential locations for the full-scale technology demonstration:

- Wheelabrator Shasta/Hudson Energy Company in Anderson, CA (stoker boiler)
- Woodland Biomass in Woodland, CA (fluidized bed)
- Wadham Energy in Williams, CA (suspension burning)

Based on the resource assessment, target opportunity biomass fuels are selected for use in the proceeding CCG laboratory and pilot scale demonstration testing tasks.

### ***Task 2 – Laboratory Scale Gasification Screening Experiments***

The objective of this task is to assess gasification characteristics of the opportunity biomass fuels selected in Task 1. Tests were conducted in the bench-scale fluidized bed reactor located in the Biomass Laboratory at the University of California, Davis. Tests focused on evaluating the behavior of the fuels under gasification conditions, including the speciation and concentration of alkali and nitrogenous species in the gas prior to combustion and in the combustion products past the gas flare. Investigation was also made on potential bed agglomeration as a function of bed temperature and fuel type, and fouling deposition.

### ***Task 3 – Kinetics of Biomass and Waste Particles Gasification/Reburning***

The objective of this task is to develop and validate a kinetics model for predicting chemical transformations of biomass/waste fuel when subjected to gasification and reburning conditions and for predicting process performance. Experiments using the opportunity biomass fuels selected in Task 1 were conducted at Stanford University using an atmospheric, laminar flow reactor. Biomass char conversion and devolatilization rates were correlated with temperature, heating rate and ambient gas composition. A predictive model was developed based on experimental results.

### ***Tasks 4/5 – Pilot Scale Cofiring/Reburning Stoker Simulation Tests***

This task demonstrates the application of the CCG technology to a pilot-scale stoker combustor boiler. The objectives of the testing are to: (1) determine the optimum firing mode

(cofiring or reburning), (2) define achievable reductions in NO<sub>x</sub> and other pollutant emissions, and (3) provide operating data for designing a full-scale system. The strategy for defining optimum operating conditions is to vary both the way the gasifier is operated and the way in which the gasification products are added to the stoker combustor. Testing is conducted using the GE Energy and Environmental Research Corp. (GE EER) pilot-scale fluidized bed gasifier / stoker-boiler simulator facility located in Irvine, California.

A series of parametric tests were conducted to define the optimum-firing mode and to determine the influence of major process parameters on performance. Test variables included:

- *Firing modes* – Test modes included: (1) gasification-products cofiring, (2) gasification-products reburning, and (3) advanced reburning. For the cofiring tests the gasification products were added at the same location as the main boiler fuel. For reburning, the gasification products were added as the reburn fuel downstream of the main fuel, and then overfire air was added into the upper furnace. For each of the gasification products cofiring and gasification products reburning modes, the primary indicators of process performance included flue gas constituents monitoring and basic system operability. In addition, tests were conducted in the advanced reburning mode, including injection of an N-agent and advanced reburning promoters.
- *Waste fuel type* – Testing was performed using the six biomass opportunity fuels identified in Task 1. System performance was evaluated as a function of waste composition, which impacts the composition of the gasification products.
- *Gasifier operation* – Evaluations were made of the stoker combustor operation as the fluidized bed gasifier stoichiometry, temperature of gasification products at the injection point, air/oxygen injection rate, and auxiliary natural gas injection rate were varied.
- *Gasification heat input* – Heat input of gasification products to the combustor was varied from 10% to 30% to determine the impacts on emissions and combustor performance.
- *Alkali compound injection* – Tests were conducted to determine if biomass and waste fuels with high alkali concentrations could provide N<sub>2</sub>O control. The impact of the addition of varying concentrations of sodium and potassium compounds to the process is assessed on the correlation between N<sub>2</sub>O emission reductions and alkali concentrations.

Finally, a series of optimization tests in which all variables are simultaneously optimized were conducted to define the best achievable performance and maximum NO<sub>x</sub> control.

### ***Task 6 – Evaluation of Slagging, Fouling, and Byproduct Emissions***

The CCG technology is designed to reduce pollutant emissions in an economic manner by using low-grade biomass/waste fuels. Different low-grade fuel feedstocks, however, have different ash characteristics, which may impact combustor ash deposition, heat-transfer patterns and combustor thermal efficiency. In addition, the CCG technology may impact toxic byproduct emissions. The objective of this task was to determine if a CCG technology causes unacceptable impacts upon combustor ash deposition or adverse impacts on emissions of toxic byproducts.

Work focused on characterizing and comparing furnace slagging deposits, convective pass fouling deposits, and the related effects of these deposits upon heat transfer and combustor thermal efficiency under two operating modes: straight biomass firing (as a baseline) and waste gasification cofiring/reburning.

Additional work involved evaluating toxic organic and metal byproduct emissions as a result of the CCG.

### ***Task 7 – Process Modeling***

The purpose of this task was to develop and use a computational model to predict CCG process performance (particularly NO<sub>x</sub> emissions performance) for a variety of waste compositions and operating conditions. The computational model is used to aid in planning and optimizing pilot-scale tests (Tasks 4/5) and in analyzing data derived from those experiments.

The chemical mechanism adopted for kinetic modeling included homogeneous oxidation reactions and, as necessary, heterogeneous reactions on the surface of biomass or waste particles. Results from laboratory experiments in Tasks 2 and 3 were used as a gauge to define gasification products and characteristic times of the reaction between particles and the gas phase species at different temperatures and gas composition.

### ***Task 8 – Design Methodology/Application***

The objective of this task was to develop a preliminary conceptual process design for a full-scale biomass boiler application of the CCG technology. The design methodology includes:

- *Data Acquisition* – Determine the characteristics of the full-scale application including furnace arrangement, firing configuration details, fuel composition, normal operating conditions (loads, excess air, sootblowing schedule, etc.), operational problems (such as

slagging, fouling, opacity excursions or capacity derates), and emission control needs (especially NO<sub>x</sub>).

- *Initial Analysis* – Using heat transfer analysis, calculate the furnace and convective pass process conditions including nominal temperatures and flow patterns.
- *Preliminary Process Design* – Based on the desired process parameters developed during Tasks 4 to 7, determine a preliminary arrangement for the cofiring/reburning components, including the elevations of fuel and air. This includes preparing preliminary injector designs, based on mixing models and alternate jet designs.
- *Process Performance Predictions* – Use process design parameters to project NO<sub>x</sub> control and boiler performance impacts.

This design methodology was also used to assess CCG retrofitting designs for the three host-site biomass boiler facilities.

## ***Task 9 – Economic and Market Analyses***

### **Economics Evaluation**

The objectives of this task were to: (1) conduct economic analysis of a full-scale boiler application of the CCG technology, (2) determine if a full-scale demonstration would be cost effective, and (3) conduct a market analysis of biomass power plants to determine potential applications for CCG technology after a full-scale demonstration.

An economic evaluation of the CCG technology was applied to each of the three potential host-site boilers as case study model plants. The economic study involved evaluating capital investment and operating costs for the CCG. Capital investment costs covered: waste unloading, storage, transfer and injection; any ancillary equipment or auxiliary fuel required for start up or emissions clean up; any upgrading of air pollution control or monitoring equipment required for regulatory compliance; permit activities and fees; and engineering services (design, permitting, construction and start up). A life cycle cost analysis of the CCG technology was performed using the Technology Assessment Guide approach from Electric Power Research Institute.

Sensitivity studies were performed for the cost elements known or suspected of having a significant impact on economic viability including parametric analyses of size, labor costs, tipping fees, and cost of capital versus inflation factors.

## Market Analysis

Based on CCG process performance and economic estimates, potential market size for the application of the CCG technology was estimated.

### *Task 10 – Production Readiness Plan*

A production readiness plan was developed. The plan includes:

- Identification of critical production processes, equipment, facilities, manpower, and support systems that will be needed to produce a commercially viable product.
- Capacity constraints imposed by the design under consideration for internal manufacturing capabilities, as well as suppliers.
- Identification of hazardous or non-recyclable materials.
- A projected “should cost” for the product in production at some expected rate.
- The expected investment threshold required to launch the commercial product.
- An implementation plan to ramp up to full production.

## **2.0 Conclusions and Recommendations**

### **2.1 Meeting Technical Objectives**

A number of biomass waste fuel streams are potentially available at competitive costs for use in the CCG technology: (1) nut shells; (2) woody fuels, including whole tree chips from forest slash and thinning, orchard clearings and pruning, urban wood, yard wastes, construction wastes, and brush field clearings; (3) municipal sewage sludge; (4) non-recyclable mixed paper; and (5) rice straw.

The targeted biomass waste fuels are shown to all be effectively gasified in conventional gasification systems, and capable of generating producer syngas which can be reburned or cofired in existing California biomass fired boilers to produce electricity and reduce NO<sub>x</sub>.

Biomass gasification kinetics and reburning models were developed and validated by test data. These models accurately predict optimum CCG performance and can be used to design and scale-up the CCG system. It was experimentally demonstrated that optimized biomass reburning using the CCG technology can achieve up to 65% NO<sub>x</sub> control. Using advanced reburning, up to 90% NO<sub>x</sub> control can be achieved.

From pilot-scale experimental data, it was determined that CCG biomass reburning does not cause significant increase in boiler slagging or fouling. Moreover, trace organic and metal emissions from biomass boilers are not projected to increase due to CCG application.

Conceptual designs for the application of CCG to three existing California biomass boilers were successfully developed. No engineering “show-stoppers” were identified.

### **2.2 Meeting Economic Objectives**

For biomass opportunity fuels such as waste paper, sewage sludge, and nutshells, CCG NO<sub>x</sub> control cost effectiveness is significantly better (lower by more than 25%) than that for existing biomass boilers.

### **2.3 Commercialization Potential**

All of the technology components for the CCG system are commercially available and well developed and demonstrated. This includes the biomass gasifier and reburning system that integrates the gasifier into an existing boiler.

Pilot scale results achieved in this project are very encouraging. The CCG is ready for a full-scale demonstration, which is the next critical “pre-commercialization” step. Full-scale demonstration is required to further progress the viability of the CCG, particularly to convince biomass boiler owners and operators of the long-term capabilities of the CCG technology.

An estimated 3 million tons of biomass residues are available in California for energy production. These biomass streams include: (1) nut shells, (2) woody wastes, (3) sewage sludge, (4) mixed waste papers, and (5) rice straw. CCG can increase the usage of these available biomass waste streams in existing biomass boilers. Renewable energy tax incentives will likely be needed to make the use of rice straw economical. The use of low-cost fuels is the primary motivation for utilizing the CCG technology in existing biomass boilers. NO<sub>x</sub> reduction is important but is currently of secondary interest to some biomass boiler operators. The potential for more restrictive future NO<sub>x</sub> regulations on biomass boilers may increase the importance of NO<sub>x</sub> reduction capabilities of the CCG technology.

## **2.4 Benefits to California**

### **2.4.1 Environmental**

The CCG technology produces a number of critical environmental benefits to California. These include:

- *Air quality* – Reduction of NO<sub>x</sub> and CO emissions from existing biomass boilers, as well as reduction of NO<sub>x</sub>, CO, and particulate emissions from open burning of agricultural and forest residues.
- *Landfill space* – Reduction of the amount of wastes (particularly municipal solid waste (paper, yard trimmings, wood wastes, etc. and sewage sludge) going to landfills.
- *Forest management* – Reduction of forest thinning wastes from forest management activities.
- *Water quality* – Reduction of water contamination from waste runoffs from landfill operations, open burning sites, and agricultural operations.

### **2.4.2 Energy**

The CCG technology produces renewable, cost competitive energy that will help California maintain a reliable and stable energy supply.

### **2.4.3 Employment**

Implementation of the CCG technology will directly add to the employment of California workers by: (1) encouraging new biomass waste processing, handling, and transportation activities, and (2) increasing biomass energy boiler operations in California.

## 3.0 Discussion

### 3.1 *Assessment of California Biomass Resources for Gasification*

The availability and cost of biomass waste fuel resources in California that have potential for use in the Close-Coupled Gasification (CCG) technology is assessed. Three existing California biomass waste combustor power plants are targeted as potential host sites for the full-scale integration and demonstration of the CCG technology. These host sites are: (1) Wadham Energy in Williams, CA; (2) Woodland Biomass Power in Woodland, CA; and (3) Wheelabrator Shasta / Hudson Energy in Anderson, CA. Based on biomass waste fuel availability and cost, and the needs of the potential host sites, California biomass waste fuels were assessed and ranked to determine candidates for use in laboratory and pilot-scale Phase I CCG testing evaluations. Results from this study are summarized and discussed below.

#### 3.1.1 **Biomass Waste Production, Availability, and Cost**

The gross production, distribution, availability, and cost of various biomass waste streams is estimated in Table 3 for various waste categories including: (1) field and seed crop residues; (2) fruit and nut crop wastes; (3) food processing wastes; (4) livestock manure; (5) forest slash; (6) forest thinning; (7) lumber mill waste; (8) chaparral; (9) municipal solid wastes, including urban wood, urban yard, waste paper, waste plastic, and used tires; (10) sewage sludge; and (11) miscellaneous industrial wastes. The top two rows of Table 3 summarize, for each of the different waste types, both:

- *Gross waste production* – The total amount of waste that is generated, and
- *Available amount* – The fraction of the gross production that is estimated to be available for use in the CCG (i.e., the total gross amount minus the amount which would not likely be obtainable due to reasons such as value in use for other purposes, difficulty in collecting or processing, etc).

The total available amount is broken down by distribution by county in the following rows below (organized alphabetically by county name).

Also provided in the last three columns of Table 3 are estimated delivered waste costs to each of the three potential host-site biomass combustion boilers. Table 4 summarizes the cost assumptions used to estimate purchase/collection costs and transportation costs.

Table 5 summarizes total biomass resources and estimated uses. Table 6 summarizes the resource availability for each of the major California waste resource categories, including non-delivered cost, gross and available quantities, and major advantages and disadvantages. Agricultural and forest residue data were taken from recent California Energy Commission assessments and industry statistics. The resource availability evaluation considered several factors impacting waste availability, including: (1) current waste handling and processing practices, (2) alternative and competing uses, (3) distribution of wastes on a regional (county) basis, (4) seasonality of waste generation, (5) gasifier feedstock requirements, and (6) sustainability (future expected generation) of waste.

### **3.1.2 Current Fuel Usage and Future Desires at Host-Site Biomass Boilers**

#### ***Wadham Energy – Williams, CA***

Wadham currently exclusively burns rice hulls. There is desire to expand this to other fuels including:

- *Almond and walnut shells* – Good availability at low cost, but high potassium levels in shells limits ability to use them in current biomass boilers setup.
- *Olive pomace* – Olive-processing wastes including pits and flesh. Good availability at low cost, but slagging and fouling from high sodium in ash limits their use in boilers.
- *Sanderdust* – “Sanderdust” is a byproduct of flooring manufacturing. Good availability at low cost (although may go to new particle board facilities). The sanderdust contains formaldehyde and urea that result in sulfur and NO<sub>x</sub> emissions in the current boilers.
- *Rice straw* – Available, but potential cost is a concern.

The plant currently has an estimated upper limit on acceptable fuel cost at about 1.25 \$/MMBtu (or about 20 \$/BDT). This generally constrains the fuel options to those that are both local and low cost. Also, the plant sells the bottom and baghouse ash to the steel industry for use in ladle lining. Thus, it will not use any fuels that would impact the quality of the ash and ability to market it to the steel industry.

#### ***Woodland Biomass Power Ltd. – Woodland, CA***

The Woodland Biomass Power facility uses a circulating fluidized bed combustor to burn:

- *Agricultural wastes* – Including orchard pruning and clearings, nutshells (almond and walnut), fruit pits, rice hulls, and alfalfa straw.
- *Urban wood waste streams* – Including tree trimmings from transportation department clearing operations, sawdust, and hog fuel.
- *Pre-consumer plastic, paper and wood* – Including waste polystyrene, paper, plywood, and particleboard prior to consumer use.

Rice straw and other grain straws and nutshells are identified as target streams that could be used with a gasification system. There is also interest in exploring the use of municipal wastes and sewage sludge.

#### ***Wheelabrator Shasta / Hudson Energy Co. – Anderson, CA***

The plant was originally designed to process lumber mill waste and forest residues (slash and thinning). It has expanded its range of fuels to accept urban tree and yard trimmings, urban “hog” fuel wood (including railroad ties contaminated with creosote), orchard trimmings and removals, nutshells, manzanita from local brush clearing activities, and pre-consumer non-recyclable waste paper (including cardboard and waxed paper). The various potential waste fuels are carefully blended into a homogeneous mixture prior to firing to account for compositional differences which may lead to boiler operational problems (such as high temperature, fouling, slagging, etc.)

The facility is interested in burning more brush clearings (chaparral). This stream will be significant in the future due to the trend of requiring brush clearing prior to and after subdivision development. Also it is anticipated that forest thinning and clearings will be an important fuel stream in the future due to the need for fire prevention in California National forests (for example, that planned in the Quincy / Plumas area). Forest slash generation is increasing due to the use of whole tree harvesting. The facility is also interested in burning rice straw and other field and seed stalks and straws and nutshells in greater quantities, as well as olive pits and other fruit and nut pits. The facility is not interested or currently permitted to burn post-consumer municipal wastes, particularly because the facility is not located close to a significant supply and due to the permitting difficulties in burning municipal post consumer wastes.

### **3.1.3 Selection of Biomass Waste Fuel for Use in CCG Research Testing**

Biomass waste fuel resources were prioritized into categories to aid in selecting the fuels to be evaluated in the CCG program experimental tasks (Phase I). Fuels were categorized based

on availability and cost, and based on host-site boiler and other project participants input during program review meetings. Primary and secondary biomass fuel candidates are summarized below. Biomass fuels, which were selected based on ranking for testing in Phase I CCG program, are also included below.

### ***Primary Candidates***

- |   |                    |  |
|---|--------------------|--|
| 1 | Rice Straw         | Available (open burning phase-out), potential for tax/farmer subsidy, Slagging fuel.   |
| 2 | Nut Shells         | Available, low cost, slagging fuel.  |
| 3 | Olive Pits         | Available, low cost, slagging fuel.  |
| 4 | Woody Fuels        | Includes wood mill wastes, whole tree chips from forest slash and thinning, orchard clearings and pruning, urban wood and yard wastes (including construction wastes), and brush field clearings. Used extensively in Shasta/Hudson and Woodland potential host-site biomass boilers. Also, important for fire prevention / forest health, and reduction of MSW. |
| 5 | Sewage Sludge      | Pressure on use as land fertilizer. Tipping fee potential.   |
| 6 | Paper and Plastics | Non-recyclable. Large gross production. CA state required reduction of municipal solid waste (MSW) to landfill. Tipping fee potential.   |

### ***Secondary Candidates***

- |    |                  |   |
|----|------------------|---|
| 7  | Wheat Straw      | Might include olive pits, almond and walnut shells. Slagging fuel. Existing supply, although smaller gross amounts. |
| 8  | Fruit Pits       | Cherry, peach, and prune pits. Small amounts.   |
| 9  | Rice Hulls       | Used in large amounts in the Wadham potential host site boiler.   |
| 10 | Livestock Manure | Some feedlot manure available. High moisture.   |

### ***Fuels Selected for CCG Program Testing***

Based on the above ranking, six biomass waste fuels were chosen for use in the Phase I CCG research-testing program. With help from host-site biomass boiler representatives, enough quantities from the selected fuels were obtained from Northern California and subsequently shipped to the GE EER Test Site in Irvine for processing. Appropriately sized portions were then distributed to UC Davis to conduct lab-scale gasification tests (Task 2), and to Stanford University to perform kinetic and biomass char burnout evaluations and modeling (Task 3). The

bulk of the selected fuels were kept in Irvine to be used in the GE EER pilot-scale facilities tests. These tests focused on cofiring and reburning applications for optimizing NO<sub>x</sub> control performance, and on evaluating the impact of the CCG technology on fouling and slagging behavior in biomass boilers (Tasks 4 through 6). The six selected biomass fuels are listed below.

- *Whole tree woodchips* – Tree chips from a mixture of coniferous and California Oak trees taken from the Western slopes of the Sierra Nevada were obtained from Wheelabrator Shasta Energy. (Referred to as Wood “W”).
- *Orchard pruning* – Walnut orchard pruning from the Sacramento Valley were obtained from Wheelabrator Shasta Energy. (Referred to as Wood “P”).
- *Non-recyclable waste paper* – Non-recyclable paper consisting of approximately 80% non-waxed cardboard and 20% soft wood (shredded cardboard and wood crates) was obtained from Woodland Biomass Power.
- *Almond shell* – The almond shells biomass fuel from Central Valley almond processors was obtained by Wheelabrator Shasta Energy.
- *Rice straw* – Non-leached, rice straw from Sutter County was obtained by U.C. Davis.
- *Municipal sewage sludge* – Sludge after anaerobic digestion was obtained from EBMUD Oakland CA by UC Davis, and Ontario County CA wastewater municipal treatment facilities by GE EER in Irvine.

Table 3. Availability, gross production, and cost of biomass waste resources.

	Field and Seed Crops					Cost (\$/BDT)		
	Rice	Wheat	Corn (Grain)	Cotton	Barley	Woodl	Will	Ander
Gross Prod (MBDT/yr)	1.083	0.900	1.150	1.400	0.200			
Available (MBDT/yr)	0.650	0.500	0.600	0.700	0.100			
Available By County								
Alameda		0.001			0.000	52	58	75
Alpine								
Amador		0.000	0.001			46	54	71
Butte	0.128	0.008	0.003		0.001	46	40	46
Calaveras								
Colusa	0.162	0.027	0.013		0.001	38	32	52
Contra Costa		0.003	0.009		0.000	46	56	75
Del Norte								
El Dorado								
Fresno	0.009	0.030	0.026	0.208	0.010	75	84	103
Glenn	0.106	0.020	0.022		0.002	46	38	45
Humboldt								
Imperial		0.069		0.008		158	167	184
Inyo								
Kern	0.001	0.019	0.012	0.168	0.009	100	109	127
Kings		0.029	0.026	0.153	0.010	82	91	109
Lake		0.000				47	38	55
Lassen		0.001	0.000		0.000	84	75	58
Los Angeles					0.000	123	132	150
Madera		0.012	0.028	0.026	0.002	84	75	93
Marin								
Mariposa								
Mendocino								
Merced	0.013	0.011	0.026	0.038	0.001	59	68	86
Modoc		0.002				93	86	69
Mono								
Monterey		0.001	0.002		0.010	79	86	109
Napa								
Nevada								
Orange					0.000	146	138	156
Placer	0.018	0.001				40	47	63
Plumas								
Riverside		0.022	0.001	0.014	0.004	152	161	179
Sacramento	0.017	0.019	0.072		0.000	37	46	63
San Benito		0.003			0.004	77	86	104
San Bernardino					0.000	141	150	167
San Diego								
San Francisco								
San Joaquin	0.007	0.044	0.164		0.002	45	54	71
San Luis Obispo		0.008			0.020	94	104	124
San Mateo								
Santa Barbara		0.002			0.001	117	127	144
Santa Clara		0.003			0.000	63	75	92
Santa Cruz								
Shasta		0.001			0.000	63	54	38
Sierra								
Siskiyou		0.009				77	68	52
Solano		0.042	0.088		0.008	40	52	69
Sonoma								
Stanislaus	0.003	0.005	0.005		0.002	52	61	78
Sutter	0.104	0.017	0.010		0.002	38	38	56
Tehama	0.003	0.003	0.005		0.000	54	46	38
Trinity								
Tulare		0.032	0.032	0.085	0.008	83	92	109
Tuolumne								
Ventura								
Yolo	0.037	0.056	0.054		0.002	36	38	56
Yuba	0.041	0.001	0.002			38	40	56
Others				0.000	0.000	52	52	52

Table 3. Availability, gross production, and cost of biomass waste resources (continued).

	Fruit and Nut Orchard Crops						Cost (\$/BDT)		
	Almonds	Walnuts	Grapes	Oranges, Lemons	Peaches	Other	Woodl	Will	Ander
Gross Prod (MBDT/yr)	0.345	0.117	0.878	0.163	0.085	0.351			
Available (MBDT/yr)	0.121	0.041	0.307	0.057	0.030	0.123			
Available By County									
Alameda		0.000					34	37	49
Alpine									
Amador		0.000	0.001				30	35	47
Butte	0.011	0.003			0.001	0.003	30	26	30
Calaveras		0.000				0.000	31	37	49
Colusa	0.005	0.001				0.001	24	20	34
Contra Costa	0.000	0.000				0.001	30	37	49
Del Norte									
El Dorado		0.000				0.001	29	34	45
Fresno	0.009	0.001	0.115	0.006	0.008	0.011	49	56	69
Glenn	0.004	0.001				0.003	30	24	29
Humboldt						0.000	65	59	49
Imperial									
Inyo									
Kern	0.021	0.000	0.030	0.008		0.005	67	73	85
Kings	0.001	0.001	0.002		0.002	0.002	54	61	73
Lake	0.000	0.002	0.001			0.005	30	24	36
Lassen									
Los Angeles						0.000	83	89	101
Madera	0.010	0.000	0.038		0.001	0.009	56	49	62
Marin									
Mariposa									
Mendocino			0.005			0.003	37	34	45
Merced	0.019	0.002	0.007		0.003	0.006	38	45	57
Modoc									
Mono									
Monterey		0.000	0.015			0.000	53	57	73
Napa		0.000	0.013				26	30	39
Nevada			0.000			0.000	30	30	45
Orange				0.001		0.000	99	93	105
Placer		0.000				0.000	26	30	41
Plumas									
Riverside		0.000	0.001	0.005	0.000	0.002	103	109	121
Sacramento		0.000	0.002			0.007	23	30	41
San Benito		0.001	0.001			0.002	51	57	69
San Bernardino			0.002	0.002		0.000	95	101	113
San Diego			0.000	0.004		0.008	99	105	117
San Francisco									
San Joaquin	0.011	0.006	0.021		0.001	0.003	29	35	47
San Luis Obispo	0.001	0.001	0.003	0.000		0.001	63	69	84
San Mateo									
Santa Barbara		0.000	0.003			0.002	79	85	97
Santa Clara		0.000	0.001			0.001	41	49	61
Santa Cruz			0.000			0.003	46	49	61
Shasta		0.000					41	35	24
Sierra									
Siskiyou									
Solano	0.001	0.001	0.001		0.000	0.001	26	34	45
Sonoma		0.000	0.013			0.003	30	34	45
Stanislaus	0.020	0.005	0.007		0.005	0.006	34	40	52
Sutter	0.001	0.003			0.004	0.004	24	24	37
Tehama	0.002	0.003				0.004	35	30	24
Trinity									
Tulare	0.003	0.005	0.024	0.024	0.003	0.014	55	61	73
Tuolumne						0.000	39	45	57
Ventura				0.007		0.003	83	89	101
Yolo	0.002	0.001	0.001			0.001	22	24	37
Yuba	0.001	0.001			0.002	0.002	24	26	37
Others	0.000			0.000	0.000	0.004	34	34	34

Table 3. Availability, gross production, and cost of biomass waste resources (continued).

	Food Processing						Cost (\$/BDT)		
	Almond Shells	Walnut Shells	Fruit Pits	Olive Pits	Rice Hulls	Cotton Gin Waste	Woodl	Will	Ander
Gross Prod (MBDT/yr)	0.250	0.130	0.045	0.010	0.340	0.260			
Available (MBDT/yr)	0.200	0.060	0.020	0.005	0.100	0.200			
Available By County									
Alameda		0.000					26	30	43
Alpine									
Amador		0.000	0.000				21	27	41
Butte	0.013	0.005	0.001	0.000	0.020		21	17	21
Calaveras		0.000		0.000			23	30	43
Colusa	0.006	0.001	0.000		0.025		15	11	26
Contra Costa	0.000	0.000	0.000				21	29	43
Del Norte									
El Dorado		0.000					20	26	39
Fresno	0.017	0.001	0.001	0.000	0.001	0.069	43	50	64
Glenn	0.004	0.002	0.001	0.000	0.016		21	15	20
Humboldt									
Imperial						0.002	107	114	127
Inyo									
Kern	0.049	0.001	0.000	0.000	0.000	0.045	63	70	83
Kings	0.002	0.002	0.000	0.000		0.041	49	56	70
Lake		0.001	0.000				22	15	28
Lassen									
Los Angeles			0.000				80	87	101
Madera	0.017	0.001	0.000	0.000		0.007	50	43	57
Marin									
Mariposa									
Mendocino			0.000				29	26	39
Merced	0.031	0.003	0.001	0.000	0.002	0.011	31	38	52
Modoc									
Mono									
Monterey		0.000					47	52	70
Napa		0.000					17	21	32
Nevada									
Orange									
Placer		0.000			0.003		17	22	34
Plumas									
Riverside		0.000	0.000			0.003	102	110	123
Sacramento		0.000			0.003		14	21	34
San Benito		0.001	0.000				45	52	65
San Bernardino									
San Diego									
San Francisco									
San Joaquin	0.016	0.010	0.001		0.001		20	27	41
San Luis Obispo	0.000	0.000					58	65	81
San Mateo									
Santa Barbara		0.000					76	83	96
Santa Clara		0.000	0.000				34	43	57
Santa Cruz									
Shasta		0.000					34	27	15
Sierra									
Siskiyou									
Solano	0.000	0.001	0.000				17	26	39
Sonoma		0.000	0.000				21	26	38
Stanislaus	0.033	0.009	0.005		0.000		26	33	46
Sutter	0.002	0.004	0.003		0.017		15	15	29
Tehama	0.002	0.004	0.001	0.001	0.000		27	21	15
Trinity									
Tulare	0.005	0.009	0.001	0.002		0.021	49	57	70
Tuolumne									
Ventura									
Yolo	0.002	0.002	0.000		0.006		13	15	29
Yuba	0.001	0.002	0.001		0.007		15	17	29
Others	0.000		0.000	0.000		0.000	26	26	26

Table 3. Availability, gross production, and cost of biomass waste resources (continued).

	Livestock Manure					Cost (\$/MBtu)		
	Dairy Cows	Beef Cattle Confined	Turkey Broilers	Chicken Broilers	Chicken Layers	Woodl	Will	Ander
Gross Prod (MBDT/yr)	2.600	1.200	1.100	0.300	0.500			
Available (MBDT/yr)	0.800	1.080	0.000	0.000	0.000			
Available By County								
Alameda								
Alpine								
Amador								
Butte	0.001					42	32	42
Calaveras	0.000					46	63	93
Colusa	0.000					28	18	52
Contra Costa	0.001					42	61	93
Del Norte	0.002					162	146	114
El Dorado								
Fresno	0.039	0.270				93	109	142
Glenn	0.009					42	28	40
Humboldt	0.011					134	118	93
Imperial	0.000	0.270				240	256	287
Inyo								
Kern	0.012	0.108				138	154	185
Kings	0.055	0.054				105	122	154
Lake								
Lassen	0.000					109	93	63
Los Angeles	0.002					179	195	226
Madera	0.014					109	93	126
Marin	0.009					52	73	101
Mariposa								
Mendocino	0.001					61	52	83
Merced	0.080	0.108				65	81	114
Modoc								
Mono								
Monterey	0.004					101	114	154
Napa	0.001					32	42	67
Nevada								
Orange								
Placer	0.000					32	44	73
Plumas								
Riverside	0.089					230	246	276
Sacramento	0.019					26	42	73
San Benito	0.001					97	114	144
San Bernardino	0.131	0.108				209	226	256
San Diego	0.009					219	236	266
San Francisco								
San Joaquin	0.047	0.054				40	56	87
San Luis Obispo	0.001					128	144	181
San Mateo								
Santa Barbara	0.003					169	185	215
Santa Clara	0.003					73	93	124
Santa Cruz	0.000					85	93	124
Shasta	0.001					73	56	28
Sierra								
Siskiyou	0.002					97	81	52
Solano	0.001					32	52	83
Sonoma	0.026					42	52	81
Stanislaus	0.080	0.054				52	69	99
Sutter	0.001					28	28	61
Tehama	0.002					56	42	28
Trinity	0.000					89	73	52
Tulare	0.136	0.054				107	124	154
Tuolumne								
Ventura	0.002					179	195	226
Yolo	0.001					24	28	61
Yuba	0.001					28	32	61
Others								

Table 3. Availability, gross production, and cost of biomass waste resources (continued).

	Forest/Brush				Cost (\$/BDT)		
	Lumber Mill Residue	Forest Slash	Forest Thinnings	Chaparral	Woodl	Will	Ander
Gross Prod (MBDT/yr)	5.500	4.500	3.800	7.700			
Available (MBDT/yr)	0.000	3.200	1.900	0.800			
Available By County							
Alameda							
Alpine							
Amador		0.090	0.053	0.002	44	52	68
Butte	0.000	0.057	0.034	0.002	44	39	44
Calaveras		0.158	0.094	0.008	47	55	71
Colusa				0.008	37	32	50
Contra Costa							
Del Norte	0.000	0.052	0.031		107	98	82
El Dorado	0.000	0.198	0.118	0.002	43	50	66
Fresno	0.000	0.040	0.024	0.016	71	79	96
Glenn		0.032	0.019	0.008	44	37	43
Humboldt	0.000	0.522	0.310	0.008	92	84	71
Imperial							
Inyo				0.002	119	119	119
Kern	0.000	0.002	0.001	0.016	94	103	119
Kings							
Lake		0.009	0.005	0.032	45	37	53
Lassen	0.000	0.065	0.039	0.002	79	71	55
Los Angeles				0.080	115	124	140
Madera		0.063	0.037	0.008	79	71	88
Marin				0.002	50	60	75
Mariposa		0.006	0.004	0.008	62	71	87
Mendocino	0.000	0.594	0.353	0.016	54	50	66
Merced							
Modoc		0.049	0.029	0.002	88	82	66
Mono				0.002	92	92	103
Monterey				0.048	75	82	103
Napa				0.016	39	44	57
Nevada	0.000	0.032	0.019		44	44	66
Orange		0.011	0.007	0.016	137	129	145
Placer		0.153	0.091	0.002	39	45	60
Plumas	0.000	0.183	0.109		60	55	55
Riverside		0.008	0.004	0.080	142	150	166
Sacramento							
San Benito				0.016	73	82	97
San Bernardino				0.032	131	140	156
San Diego				0.080	137	145	161
San Francisco							
San Joaquin							
San Luis Obispo				0.048	89	97	117
San Mateo		0.013	0.008	0.008	55	66	76
Santa Barbara				0.080	110	119	135
Santa Clara		0.008	0.005	0.008	60	71	87
Santa Cruz		0.029	0.017	0.002	67	71	87
Shasta	0.000	0.160	0.095	0.016	60	52	37
Sierra		0.046	0.027		54	55	71
Siskiyou	0.000	0.238	0.141	0.016	73	65	50
Solano				0.002	39	50	66
Sonoma	0.000	0.073	0.043	0.002	44	50	65
Stanislaus				0.002	50	58	74
Sutter							
Tehama	0.000	0.072	0.042	0.016	52	44	37
Trinity	0.000	0.135	0.080	0.002	69	60	50
Tulare		0.026	0.016	0.016	78	87	103
Tuolumne	0.000	0.067	0.040	0.008	57	66	82
Ventura				0.064	115	124	140
Yolo				0.002	35	37	54
Yuba	0.000	0.016	0.009		37	39	54
Others							

Table 3. Availability, gross production, and cost of biomass waste resources (continued).

	Municipal/Urban Waste					Cost (\$/BDT)			Sewage Sludge	Cost (\$/BDT)		
	Urban Wood	Urban Yard	Waste Paper	Waste Plastics	Used Tires	Woodl	Will	Anders		Woodl	Will	Anders
Gross Prod (MBDT/yr)	3.200	3.900	13.000	2.500	0.400				0.700			
Available (MBDT/yr)	0.700	1.200	2.600	0.750	0.150				0.600			
Available By County												
Alameda	0.030	0.051	0.111	0.032	0.006	31	36	49	0.026	47	58	88
Alpine	0.000	0.000	0.000	0.000	0.000	37	49	58	0.000	60	88	109
Amador	0.001	0.001	0.003	0.001	0.000	27	33	47	0.001	37	51	82
Butte	0.004	0.007	0.015	0.004	0.001	27	22	27	0.004	37	27	37
Calaveras	0.001	0.001	0.003	0.001	0.000	28	36	49	0.001	41	58	88
Colusa	0.000	0.001	0.001	0.000	0.000	20	16	31	0.000	23	13	47
Contra Costa	0.020	0.034	0.073	0.021	0.004	27	35	49	0.017	37	56	88
Del Norte	0.001	0.001	0.002	0.001	0.000	80	73	58	0.000	157	141	109
El Dorado	0.003	0.006	0.013	0.004	0.001	26	31	45	0.003	35	47	78
Fresno	0.016	0.028	0.060	0.017	0.003	49	57	71	0.014	88	104	137
Glenn	0.001	0.001	0.002	0.001	0.000	27	20	26	0.000	37	23	35
Humboldt	0.003	0.004	0.010	0.003	0.001	68	60	49	0.002	129	113	88
Imperial	0.003	0.005	0.011	0.003	0.001	115	122	136	0.003	235	251	282
Inyo	0.000	0.001	0.001	0.000	0.000	90	90	90	0.000	180	180	180
Kern	0.014	0.023	0.050	0.014	0.003	69	77	90	0.012	133	149	180
Kings	0.003	0.004	0.009	0.003	0.001	55	62	77	0.002	100	117	149
Lake	0.001	0.002	0.004	0.001	0.000	28	20	34	0.001	39	23	54
Lassen	0.001	0.001	0.003	0.001	0.000	57	49	36	0.001	104	88	58
Los Angeles	0.197	0.338	0.733	0.211	0.042	88	95	108	0.169	174	190	221
Madera	0.002	0.004	0.009	0.003	0.001	57	49	64	0.002	104	88	121
Marin	0.005	0.009	0.019	0.005	0.001	31	40	53	0.004	47	68	96
Mariposa	0.000	0.001	0.001	0.000	0.000	42	49	63	0.000	72	88	119
Mendocino	0.002	0.003	0.007	0.002	0.000	35	31	45	0.002	56	47	78
Merced	0.004	0.007	0.016	0.005	0.001	37	44	58	0.004	60	76	109
Modoc	0.000	0.000	0.001	0.000	0.000	64	58	45	0.000	121	109	78
Mono	0.000	0.000	0.001	0.000	0.000	68	68	77	0.000	129	129	149
Monterey	0.008	0.013	0.029	0.008	0.002	53	58	77	0.007	96	109	149
Napa	0.003	0.004	0.009	0.003	0.001	22	27	38	0.002	27	37	62
Nevada	0.002	0.003	0.007	0.002	0.000	27	27	45	0.002	37	37	78
Orange	0.058	0.100	0.216	0.062	0.012	106	99	113	0.050	214	200	231
Placer	0.005	0.008	0.018	0.005	0.001	22	28	40	0.004	27	39	68
Plumas	0.001	0.001	0.002	0.001	0.000	40	36	36	0.000	68	58	58
Riverside	0.032	0.054	0.118	0.034	0.007	110	118	131	0.027	225	241	271
Sacramento	0.024	0.042	0.091	0.026	0.005	19	27	40	0.021	21	37	68
San Benito	0.001	0.002	0.004	0.001	0.000	51	58	72	0.001	92	109	139
San Bernardino	0.035	0.060	0.130	0.038	0.008	101	108	122	0.030	204	221	251
San Diego	0.060	0.102	0.221	0.064	0.013	106	113	127	0.051	214	231	261
San Francisco	0.016	0.027	0.059	0.017	0.003	33	40	54	0.014	51	68	98
San Joaquin	0.012	0.020	0.044	0.013	0.003	26	33	47	0.010	35	51	82
San Luis Obispo	0.005	0.009	0.019	0.005	0.001	65	72	88	0.004	123	139	176
San Mateo	0.015	0.026	0.056	0.016	0.003	36	45	54	0.013	58	78	98
Santa Barbara	0.008	0.014	0.031	0.009	0.002	83	90	104	0.007	164	180	210
Santa Clara	0.035	0.060	0.130	0.038	0.008	40	49	63	0.030	68	88	119
Santa Cruz	0.005	0.009	0.019	0.006	0.001	46	49	63	0.004	80	88	119
Shasta	0.004	0.006	0.013	0.004	0.001	40	33	20	0.003	68	51	23
Sierra	0.000	0.000	0.000	0.000	0.000	35	36	49	0.000	56	58	88
Siskiyou	0.001	0.002	0.003	0.001	0.000	51	44	31	0.001	92	76	47
Solano	0.008	0.014	0.030	0.009	0.002	22	31	45	0.007	27	47	78
Sonoma	0.009	0.016	0.034	0.010	0.002	27	31	44	0.008	37	47	76
Stanislaus	0.009	0.016	0.034	0.010	0.002	31	38	52	0.008	47	64	94
Sutter	0.002	0.003	0.006	0.002	0.000	20	20	35	0.001	23	23	56
Tehama	0.001	0.002	0.004	0.001	0.000	33	27	20	0.001	51	37	23
Trinity	0.000	0.000	0.001	0.000	0.000	48	40	31	0.000	84	68	47
Tulare	0.008	0.013	0.028	0.008	0.002	56	63	77	0.007	102	119	149
Tuolumne	0.001	0.002	0.004	0.001	0.000	38	45	58	0.001	62	78	109
Ventura	0.016	0.027	0.058	0.017	0.003	88	95	108	0.013	174	190	221
Yolo	0.003	0.006	0.012	0.004	0.001	18	20	35	0.003	19	23	56
Yuba	0.001	0.002	0.005	0.001	0.000	20	22	35	0.001	23	27	56
Others												

Table 4. Waste cost assumptions.

Waste Type	Purchase, Collect, Process Cost (\$/BDT)	Transportation Cost				
		Truck Load Size			Travel Cost (1) (\$/1-way mile/BDT)	Loading and Unloading (2) (\$/BDT)
		Wet Bulk Density (lb/ft3)	Moisture (%)	Load Size (3) (BDT)		
Field/Seed Crops						
Straw Residues	25	13	15	11.9	0.23	3.77
Fruit and Nut Crops						
Orchard Prunings	15	20	20	17.3	0.16	2.60
Food Processing						
Shells, Pits, Hulls	5	18	20	15.6	0.18	2.89
Livestock Manure	5	25	75	6.8	0.41	6.67
Lumber Mill Residues	15	20	10	19.4	0.14	2.31
Forest Slash	25	20	40	13.0	0.21	3.47
Forest Thinnings	25	20	40	13.0	0.21	3.47
Chaparral	25	18	20	15.6	0.18	2.89
Municipal Wastes						
Urban Wood	10	20	30	15.1	0.18	2.98
Urban Yard	5	20	40	13.0	0.21	3.47
Waste Paper	10	20	25	16.2	0.17	2.78
Waste Plastic	10	20	25	16.2	0.17	2.78
Used Tires	0	20	10	19.4	0.14	2.31
Sewage Sludge	0	30	75	6.8	0.41	6.67

(1) Based on truck labor and vehicle cost of \$2/1-way mile (\$45/hr, 45 round-trip miles | and fuel cost of \$0.75/1-way mile (4 mile/gal, \$1.50/gal) -- for a total cost of \$2.75/1-

(2) \$45 per truckload, based on one hour for loading/unloading at \$45/hr for truck labor vehicle cost

(3) Truck trailer with volume capacity of 80 and weight capacity of 26 actual tons

Costs adapted from CEC (1999)

Table 5. Summary of waste resources.

Stream	Gross Production (MM BDT/yr)	Current Use (MM BDT/yr)		Available (MM BDT/yr)
		Fuel (1)	Other (2)	
Chaparall	7.7			0.8
Lumber Mill	5.5	1.8	3.3	0.0
Forest Slash	4.5	0.3		2.5
Forest Thinnings	3.8	0.3		1.4
Woody Agricultural	1.9	1.0		0.7
Urban Wood	3.2	1.0	0.5	0.7
Urban Yard	3.9	0.2	0.5	1.2
Waste Paper	13.0	0.2	4.0	2.5
Waste Plastic	2.5	0.1	0.1	0.8
Field Crops	4.7	0.1		2.6
Sewage Sludge	0.7	0.1		0.6
Shells, Pits, Hulls	1.0	0.4	0.1	0.5
Livestock Manure	12.0	0.1		2.0
Total	64.4	5.5		16.3

(1) Use in biomass and municipal waste combustion units

(2) Uses such as in particle board, plywood, animal bedding, fertilizer, landscaping, etc.

Table 6. Waste biomass resource assessment for California.

<i>Waste Stream</i>	<i>Cost, Non-delivered (\$/BDT)</i>	<i>Quantity (Million BDT/yr)</i>		<i>Advantages</i>	<i>Disadvantages</i>
		Gross	Availability		
Wood mill waste	> 20	5.5	0	Clean fuel	Little available. High demand. Plywood, particleboard, landscaping material, fuel.
Forest slash	> 20	4.5	2.5	Fire prevention	Inconsistent, uncertain generation, availability, sustainability. Difficult collection.
Forest thinning	> 25	3.8	1.9		
Chaparral	> 25	7.7	0.8	Fire prevention, suburban growth	Very uncertain future collection.
Urban wood	> 30	3.2	0.7	Good fuel. CA MSW 50% reduction goal	Demand for particleboard, fuel. Separation and recovery needs.
Urban yard	> 30	3.9	1.2	Existing supply. CA MSW 50% reduction goal	Value for landscape material, landfill cover, and composting. Separation and recovery needs.
Non-recyclable waste paper	-30 to >20	13	2.5	Existing supply. CA MSW 50% reduction goal	Facility permitting. Recovery of low value mixed streams needed.
Sewage sludge	-30 to 0	0.7	0.6	Pressure on use as land treatment	Facility permitting.
Field crop straw and stalks	15 to 45	5.1	2.8	Potential supply. Rice: 15 \$/ton CA subsidy.	Slagging fuel. Rice: Open burning phase out in Sacramento Valley. Plowed under, problems? Others: Plowed under, more limited incentive
Woody agricultural wastes (fruit and nuts)	10	2	1.4	Existing supply for pruning. 10 \$/ton CA subsidy. Open burn reduction potential for nuts.	Fruit crop use as soil mulch incorporation. Nuts open burning. Collection difficulty. Clearings currently used.
Fruit pits, nut shells	10	1	0.5	Existing supply. Almond and walnut shells, fruit and olive pits	High N, P, K, Na. Small amounts.
Livestock manure	0 to 10	12		Available in confined dry feedlots. Focus on manure handling and treatment.	Much used as fertilizer and collected wet. Poultry litter not available.

## **3.2 Laboratory Scale Gasification Experiments and Modeling**

Biomass gasification experiments were conducted in the University of California, Davis (UC Davis) laboratory fluidized bed reactor. The primary objective of the laboratory scale gasification tests was to assess the behavior of the different biomass waste fuels under gasification conditions. This included determining: (1) the fate of biomass fuel elements and partitioning of reaction products among the gas, liquid, and particle phases during steady state gasifier operations; (2) speciation and concentration of alkali and nitrogenous compounds in the gasifier syngas; (3) fluidized bed agglomeration characteristics; and (4) fouling deposition in the offgas flare.

### **3.2.1 Fluidized Bed Gasification Reactor**

The UC Davis laboratory fluidized bed reactor, shown in Figure 6, has a 75 mm inner diameter. An electric furnace that surrounds the reactor controls the reactor temperature. Fluidizing air is fed to the reactor through air distribution nozzles located at the bottom of the reactor. The air can be preheated. The reactor is operated at atmospheric pressure. Biomass fuel is metered through a belt conveyor onto an injection screw feeder that introduces fuel into the bottom of the bed. Fuel is milled to a 1 mm nominal particle size prior to feeding. Bed material is usually aluminasilicate grains (with 210  $\mu\text{m}$  mean particle size), but is varied depending on the waste composition; other bed materials include magnesium oxide, alumina, zirconia, and limestone. The fluidized bed gasifier syngas passes through a disengagement zone at the top of the reactor that encourages internal circulation of bed grains and larger fuel particles. The syngas is then routed through a horizontal deposit test section, a cyclone (where entrained bed and fuel particles are separated from the reactor syngas), and a gas flare.

### **3.2.2 Experimental Procedures**

The six-biomass waste fuels, which were selected as described earlier in Section 3.1.3, were size reduced for effective feeding and operation of the fluidized bed. The wood, straw, and almond shells were knife milled to a 1 mm size. The non-recycled paper was milled to a 2 mm size. Sewage sludge was air dried, and hammer milled. Prior to gasification, the six-biomass fuels were characterized for various constituents and properties. Table 7 provides information on fuels sampling and analysis approach.

After characterization, each fuel waste was tested under gasification conditions in the fluidized bed reactor. Initially, the bed was preheated to a temperature of about 850°F. Fuel was then increased slowly over a period of 20-30 minutes to a stable feedrate of about 1-1.5 g/s. Fluidizing air was added at a rate of about 1 L/s, producing a superficial gas velocity of 0.085 m/s, and a gas residence time of 1.2 s in the main reactor column. Fuel and air injection rates were then adjusted to generate a producer syngas that has a maximum content of CO, CH<sub>4</sub>, and H<sub>2</sub> as determined by the color and robustness of the producer syngas flare. After stable bed temperature and adequate flare quality had been established, gas sampling and analysis was conducted over a period of about 30 minutes to 1 hour. After gas sampling was finished, the fuel and air supplies were cut off from the reactor, and the reactor was cooled. Material samples were collected from the reactor bed, horizontal pass, and cyclone.

Table 8 summarizes measurements made during each gasification testing series. Reactor syngas sampling included:

- Extractive, manual gas sampling trains were used to determine:
  - NH<sub>3</sub>/HCN through absorption in dilute sulfuric acid impinger solution.
  - Alkalies. Solid phase alkalies were removed in a heated filter while gas phase alkalies were removed in a condenser.
  - Tar, removed in condenser and methanol solvent solution.
- Online continuous emissions monitors used for CO, CO<sub>2</sub>, H<sub>2</sub>, and O<sub>2</sub>.
- Gas grab samples were collected and analyzed with gas chromatography for CH<sub>4</sub>, N<sub>2</sub>, CO, CO<sub>2</sub>, H<sub>2</sub>, and O<sub>2</sub>.

Solid samples were taken after testing from the reactor bed, horizontal pass and cyclone ash dropout, and deposit probes located in the disengagement section and horizontal pass.

### **3.2.3 Results and Discussion**

Biomass fuel compositions, elemental analysis of biomass fuel ash, and ash fusion temperatures are summarized in Table 9.

Gasifier operating conditions are summarized in Table 10 for each of the different biomass fuel types. Typical temperature profiles through the reactor are shown in Figure 7 for some of the biomass fuel types.

Gasifier producer syngas bulk composition is summarized in Table 11 for each of the different biomass fuel types. Gasification of all biomass fuels was readily achieved. A high

quality, robust producer syngas was generated, as evidenced by significant heating value, high amounts of CO, CH<sub>4</sub>, and H<sub>2</sub>, and low amounts of O<sub>2</sub> and CO<sub>2</sub>. The H<sub>2</sub> content ranged from 4-21%, CO from 10-22%, and CH<sub>4</sub> from 4-8%. Producer syngas heating value was strongly related to the fuel carbon content.

Alkali, chlorine, and ammonia composition of the producer syngas is shown in Table 12. As shown in Figure 8, ammonia content of the producer syngas is directly correlated to the fuel nitrogen content. However, the fuel nitrogen to ammonia conversion fraction fell as the fuel nitrogen increased. HCN levels in the producer syngas are small compared with ammonia. The concentration of chlorine or potassium in the producer syngas was not strongly related to chlorine or potassium in the feed (most condensed prior to the stack sampling location). Sodium levels in the biomass fuels were generally much lower than the potassium levels.

Bed agglomeration using standard aluminasilicate bed materials was not a problem for all fuels except, as expected, for rice straw. Gasification of rice straw required the addition of magnesium oxide to prevent bed agglomeration.

Mass balance closures for various elements are shown in Table 13. Closures are generally very good (70-150%) for the bulk constituents. For the trace constituents, as is typical, mass balances fall in a much wider range (0 – 200+ %).

### **3.2.4 Gasification Modeling**

Theoretical modeling with a “Comprehensive Simulator for Fluidized Bed Equipment” (CSFB), and a thermodynamic equilibrium gas phase solver (STANJAN) was used to predict the producer gas composition.

Concentrations of CO and H<sub>2</sub> predicted by the CSFB were consistently low. It was difficult to determine if the CSFB is not allowing sufficient carbon conversion or whether the kinetic scheme for the gas phase is inadequately calibrated. Further, the large number of input parameters makes it very difficult to adjust or manipulate the code to get meaningful results.

Predictions using STANJAN equilibrium modeling were better than CSFB, but were usually higher (predicted higher levels of CO and H<sub>2</sub>) than experimental results. Reasons for the differences might be because experimental gas sampling was performed at temperatures less than the bed temperature, gas compositions are frozen between the bed and sampling location, and the fluidized bed is short so the residence time is less than the time needed to complete devolatilization and reaction of solids.

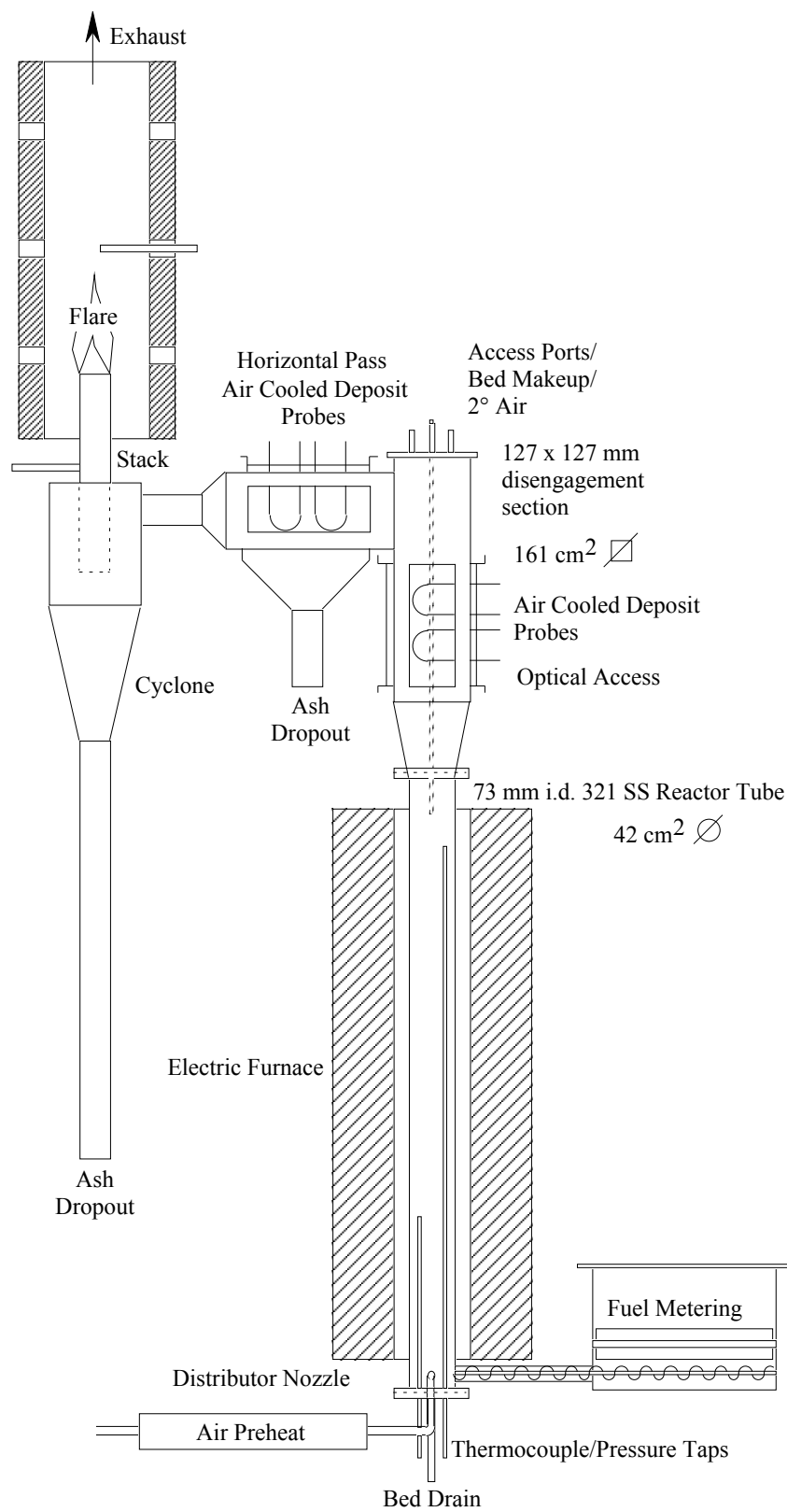


Figure 6. UC Davis fluidized bed reactor.

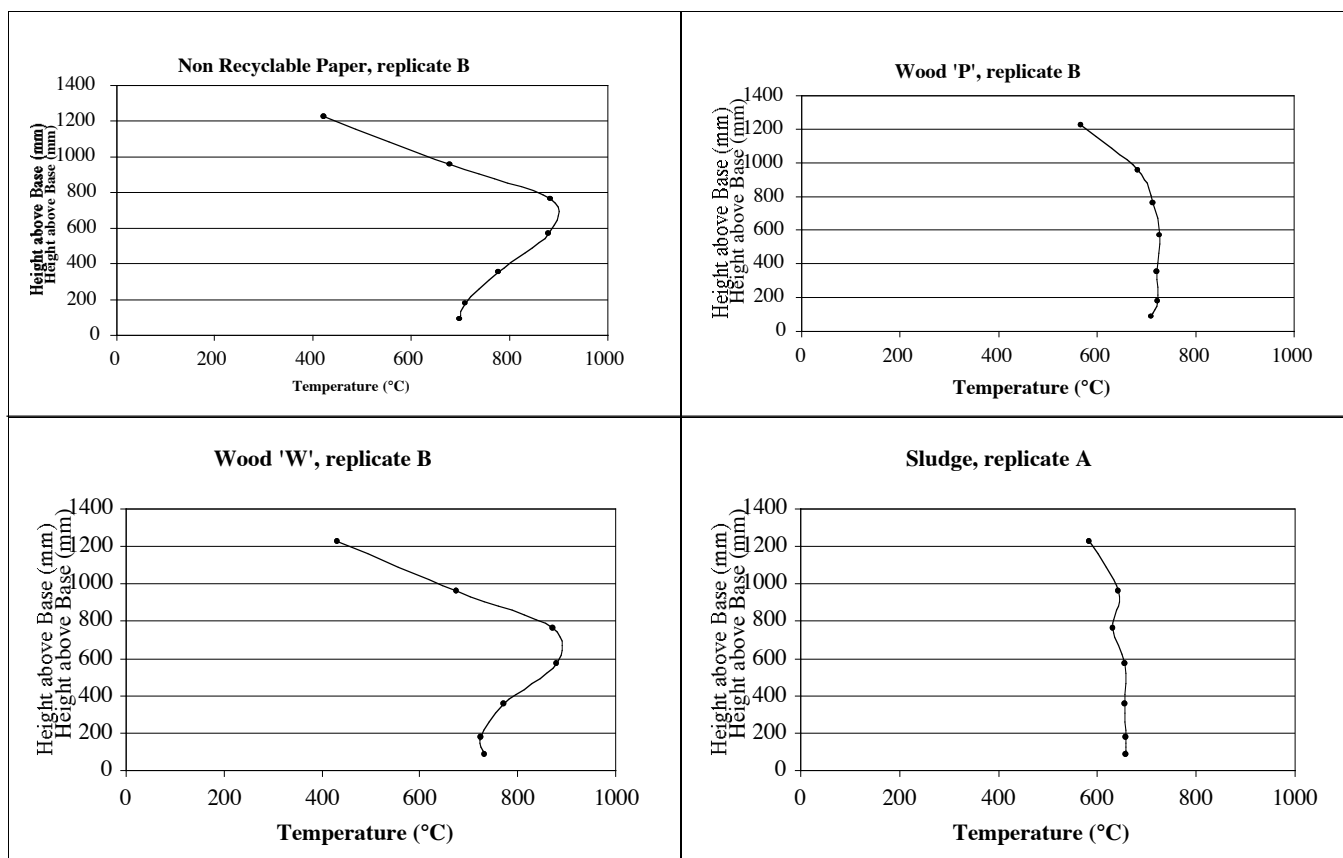


Figure 7. Typical temperature profiles through the reactor.

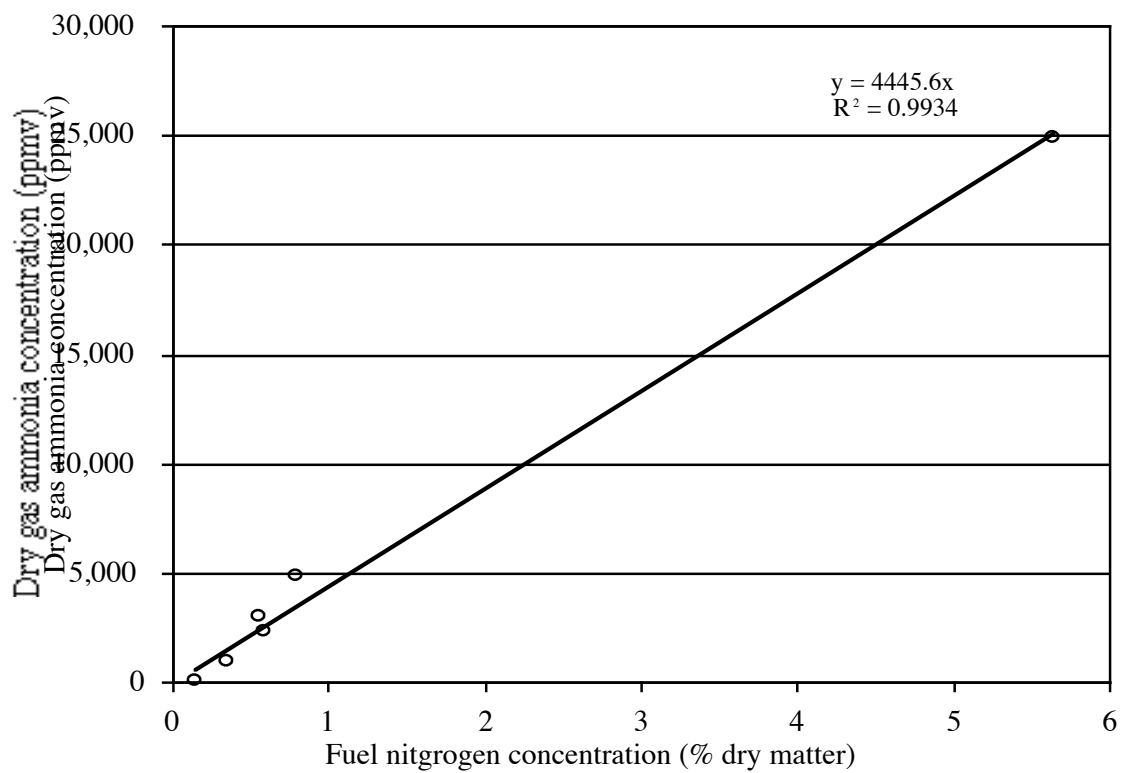


Figure 8. Ammonia content as a function of Fuel N.

Table 7. Fuel sampling and analysis.

Analysis	Method/Test Lab	Sampling
Moisture (% wet basis)	Air-oven (104±3°C) UC Davis Biomass Lab	Split batch, prior to tests Split batch, from fuel feed belt, start and end of test
Higher Heating Value (MJ kg <sup>-1</sup> )	Adiabatic Bomb Calorimeter UC Davis Biomass Lab	Split batch, prior to tests
Proximate Analysis (ash, volatiles, fixed carbon)	Muffle furnace UC Davis Biomass Lab	Split batch, prior to tests
Ash (% dry matter)	Muffle furnace, 575°C/2h UC Davis Biomass Lab	Split batch, prior to tests
Volatile matter (% dry matter)	Muffle furnace, 950°C, modified method for sparking fuels, UC Davis Biomass Lab	Split batch, prior to tests
Fixed carbon (% dry matter)	By difference on ash and volatile matter	
Ultimate Analysis (C, H, O, N, S, Cl) (% dry matter)	Hazen Research, Inc. (Golden, CO)	Split batch, prior to tests
Ash Elemental (Si, Al, Ti, Fe, Ca, Mg, Na, K, P, S, Cl, and CO <sub>2</sub> (% ash)	Hazen Research, Inc. Ashed at 575°C	Split batch, same sample as ultimate analysis
Bulk Density (kg m <sup>-3</sup> )	Volumetric, drop test UC Davis Biomass Lab	Batch, prior to tests
Particle size distribution	Sieve UC Davis Biomass Lab	Split batch, prior to tests

Table 8. Sampling and measurements for fuel screening experiments.

Sample/Measurement	Method	Location
Fuel feed rate (kg s <sup>-1</sup> )	Feed belt speed/ Total gravimetric	Fuel feeder
Fluidizing air flow rate (L min <sup>-1</sup> )	Rotameter	Primary air inlet
Fuel feeder purge air (L min <sup>-1</sup> )	Rotameter	Purge air inlet
Fresh bed mass (g)	gravimetric at start	Media weighed prior to adding to clean reactor
Fresh bed addition (g)	gravimetric at time of addition	During operation, media was added through upper lid
Fresh bed chemical composition (%)	Hazen Research, Inc. NARCO	Batch sample submitted for analysis
Spent bed mass (g)	gravimetric during or at end of test	Bed dropped from lower flange and bed discharge
Spent bed chemical composition (%)	Hazen Research, Inc.	Split sample submitted for analysis
Residual fuel/carbon in bed (g)	loss on ignition at 575°C in air muffle furnace	Split sample
Ash (kg)	gravimetric at end of test	Ash collected from horizontal pass dropout and cyclone dropout
Ash chemical composition (%)	Hazen Research, Inc.	Split sample submitted for analysis incl. metals in some cases
Deposit mass on probes (g)	mass reconstructed from elemental composition of rinsate and gravimetric determination of filtered insoluble solids	Post-flare exhaust stack probe Filtered insoluble fraction Liquid filtrate
Deposit chemical composition (%)	Hazen Research, Inc.	Filtered insoluble fraction Liquid filtrate
Gas composition (%)	CO <sub>2</sub> , CO, H <sub>2</sub> , and O <sub>2</sub> by continuous analysis	Cyclone exit
Gas composition (%)	CO <sub>2</sub> , CO, H <sub>2</sub> , O <sub>2</sub> , N <sub>2</sub> , CH <sub>4</sub> by GC on grab samples	Cyclone exit
Ammonia in gas (ppm)	via absorption in dilute acid, analysis by ion- specific electrode (ISE)	Cyclone exit Post-flare
Hydrogen cyanide in gas (ppm)	via absorption in dilute acid, analysis by Hazen Research, Inc.	Cyclone exit

Table 8 (Continued)

Sample/Measurement	Method	Location
Alkali in fly-ash (ppm)	hot gas filtration, solid samples analyzed by Hazen Research, Inc., incl. metals (for SLF), soluble fraction of K, Cl by ISE	Cyclone exit
Alkali in gas (ppm)	via absorption in water, analysis by ISE for K, Cl	Cyclone exit
Tar (mg m <sup>-3</sup> )	gravimetric via water and dry-ice condensers, methanol solvent	Cyclone exit
Temperature (°C)	Type K thermocouples	Air inlet at distribution manifold Lower bed (89 mm and 178 mm above base) Mid-bed (356 mm above base) Upper bed (572 and 672 mm above base) Disengagement zone (954 and 1226 mm beyond base) Horizontal pass (1637 mm beyond base) Cyclone exit (2128 mm beyond base) Outside reactor wall at furnace center Sampling trains
Pressure (Pa)	Piezoelectric pressure transducer	Fluidizing air inlet Reactor bottom (10 mm above bed) Reactor top at transition to disengagement zone (940 mm) Bed differential Atmospheric
Total flow (L)	dry-test meter	Sampling trains

Table 9. Compositions and ash fusion temperatures of test fuels.

	Almond Shells	Orchard pruning	Rice Straw	Whole Tree Chips	Sewage Sludge	Non- Recyclable paper
Ultimate Analysis (% db)						
Carbon	36.27	48.20	38.50	51.15	36.20	49.11
Hydrogen	3.94	4.41	3.56	3.40	4.46	5.08
Nitrogen	0.79	0.59	0.55	0.35	5.64	0.14
Sulfur	0.05	0.03	0.06	0.05	1.07	0.06
Ash	26.57	2.43	21.03	2.68	37.9	1.05
Oxygen (by diff.)	32.43	44.51	36.29	42.40	14.86	44.55
Chlorine	0.03	<0.01	0.58	<0.01	0.10	0.03
Elemental Ash (% db):						
SiO <sub>2</sub>	65.05	5.80	76.36	33.77	47.1	25.30
Al <sub>2</sub> O <sub>3</sub>	12.70	2.25	0.99	7.69	17.9	23.11
TiO <sub>2</sub>	0.45	0.09	0.05	0.34	1.22	2.07
Fe <sub>2</sub> O <sub>3</sub>	4.32	1.23	0.31	1.25	5.64	1.37
CaO	4.20	43.90	2.17	29.00	8.65	19.50
MgO	2.10	8.08	1.71	3.54	2.98	4.56
Na <sub>2</sub> O	1.87	0.31	0.30	1.21	1.33	6.31
K <sub>2</sub> O	8.54	10.60	11.90	9.01	1.32	4.44
P <sub>2</sub> O <sub>5</sub>	0.72	2.32	1.55	1.83	14.7	5.75
SO <sub>3</sub>	0.22	0.56	0.67	0.43	1.38	2.73
Cl	0.08	0.15	2.39	0.19	<0.01	0.25
CO <sub>2</sub>	0.48	23.68	0.22	3.36	0.21	1.52
Total	100.73	98.97	98.62	91.62	102.39	96.91
Ash Fusion Temperatures (°C)						
Oxidizing Atmosphere						
Initial	1172	1482+	1240	1210	1111	1202
Softening	1231		1378	1216	1127	1218
Hemispherical	1290		1429	1222	1144	1223
Fluid	1352		1470	1232	1189	1232
Reducing Atmosphere						
Initial	1192	1482+	1175	1216	1111	1095
Softening	1219		1367	1221	1121	1161
Hemispherical	1227		1406	1222	1134	1177
Fluid	1254		1420	1224	1189	1193
Ultimate Analysis (Moisture and ash free basis)						
Carbon	49.39	49.40	48.75	52.56	58.29	49.63
Hydrogen	5.37	4.52	4.51	3.49	7.18	5.13
Nitrogen	1.08	0.60	0.70	0.36	9.08	0.14
Sulfur	0.07	0.03	0.08	0.05	1.72	0.06
Oxygen (by diff.)	44.16	45.62	45.95	43.57	23.93	45.02

Table 10. Average operating parameters.

Parameter	Units	Whole Tree Chips	Walnut Pruning	Non-Recyclable Paper	Almond Shell	Rice Straw	Sewage Sludge
Test Length	(min)	75	73	105	50	76	65
Air : Fuel Ratio (AF)	(-)	1.1	0.4	1.25	0.27	0.65	0.25
Air Factor	(-)	0.23	0.09	0.25	0.07	0.17	0.05
Superficial Velocity	(m s <sup>-1</sup> )	0.41	0.41	0.36	0.34	0.41	0.33
Residence time (Reactor + Vert. Diseng. Sect.)	(s)	5.6	5.6	6.3	6.7	5.6	6.9
Average Furnace Wall Temperature	(°C)	850	850	850	835	850	840
Average Bed Temperature	(°C)	720	730	700	710	775	700

Table 11. Producer gas (% vol.)

Constituent	Walnut Pruning	Almond Shell	Non-Recyclable Paper	Sewage Sludge	Whole Tree Chips	Rice Straw
CO	21.5	19.7	20.5	11.6	16.5	13.6
H <sub>2</sub>	11.0	12.7	7.7	15.0	10.5	7.1
CH <sub>4</sub>	7.5	6.7	5.6	5.7	5.0	3.6
CO <sub>2</sub>	16.5	19.8	12.9	10.2	12.0	16.3
N <sub>2</sub>	31.0	26.7	50.3	41.1	48.5	49.4
O <sub>2</sub>	1.9	1.4	1.3	2.3	1.6	4.2
Total	89.4	87	98.2	85.9	94.1	94.1
Higher Heating Value (MJ m <sup>-3</sup> )	6.3	6.1	5.3	5.1	4.9	4.2

Table 12. Gas phase alkali, chlorine, and ammonia concentrations.

Parameter	Units	Whole Tree Chips	Walnut Pruning	Non-Recycl. Paper	Almond Shell	Rice Straw	Sewage Sludge
K	(ppmv)	10.5	16.5	2	19.5	22	45
Cl	(ppmv)	160	60	13	620	270	nd
NH <sub>3</sub>	(ppmv)	1015	2350	80	4900	3000	24900
HCN	(ppmv)	nd	nd	nd	2.3	24	nd
K <sub>part</sub> /K <sub>gas</sub> mass ratio *					5.2	2	
Cl <sub>part</sub> /Cl <sub>gas</sub> mass ratio *					<<1	<<1	

\* producer gas temperature

~200°C at extraction point

Table 13. Elements balance / closures.

Closure (%)	Whole Tree Chips	Walnut Pruning	Non-Recyclable Paper	Almond Shell	Rice Straw	Sewage Sludge
C	69	74	79	82	78	52
H	107	71	98	74	97	98
O	93	89	101	99	119	158
N	130	159	111	178	123	198
S	110	296	45	107	322	47
K	122	133	620	75	73	65
Cl	555	402	42	485	138	nd
Si	104	116	98	75	49	49
Al	88	103	88	114	13	41
Ti	99	99	94	99	13	50
Fe	606	328	345	87	114	64
Ca	107	104	118	74	139	59
Mg	105	120	124	68	2423 <sup>*</sup>	61
Na	69	152	96	66	47	57
P	290	181	95	129	88	61

\* Artifact

### **3.3 *Kinetics of Biomass Particles Gasification / Reburning***

Laboratory scale testing was conducted at Stanford University to evaluate the biomass char oxidation process and biomass devolatilization rates and yields under high temperature conditions. A char combustion model based on the oxidation of coal chars was extended to biomass chars. The char combustion model can be used to assist in the evaluation and prediction of the behavior of biomass chars in the close-coupled reburning arrangement.

#### **3.3.1 Char Gasification Model**

A biomass char gasification model was developed to predict the behavior of biomass char particles when exposed to hot, gaseous environments. The model assumes that the spherical char particle consists of two components – ash and carbonaceous material. The ash remains with the particle throughout the char conversion process whereas the carbonaceous material is gasified. The overall char-particle conversion rate is controlled by: (1) the transport of reactive gases and energy across the boundary layer surrounding the particle, (2) the transport of gases through the porous structure of the particle, and (3) the chemical reactions that take place on the carbonaceous surfaces within the particle. In the model, the rate limiting process is determined by the instantaneous state of the particles, as characterized by its temperature, size, apparent density, specific surface area, and intrinsic chemical reactivity. A four-step heterogeneous reaction mechanism is used to describe char reactivity, and char particle temperature is calculated assuming a state of thermal equilibrium between the particle and its surroundings.

Inputs to the model include particle size, density, surface area, and gas temperature and composition (oxygen). Model outputs include the mass loss rate (burning rate), particle size, specific surface area, particle temperature, and CO and CO<sub>2</sub> evolution rates.

#### **3.3.2 Experimental System and Testing Procedures**

Experimental activities focused on quantifying the various parameters that are used in the biomass char conversion model. This is done by examining biomass chars at various extents of conversion to determine changes in particle size, apparent density, and specific surface area with mass loss. Variations in intrinsic chemical reactivity of the particles are also assessed in terms of the particle temperature and oxygen availability.

### *Entrained Laminar Flow Reactor*

An entrained laminar flow reactor (LFR) was used to simulate the high temperature reburning process. The entrained flow reactor produces information on biomass fuel devolatilization rates (mass loss rates) and produces biomass char samples at various stages of conversion (oxidation). The entrained flow reactor is a 5x5 cm square chamber. Biomass fuel materials were ground and screened to produce a particle size distribution of less than about 150  $\mu\text{m}$ . Biomass fuel particles were injected at the base of the reactor at a rate of about 1 g/hr. The reactor environment was maintained at about 1,000°C and 8% oxygen through an array of diffusion flamelets fueled by  $\text{CH}_4$  and  $\text{H}_2$ , located at the bottom of the reactor. Heating rates on order of  $10^4$  -  $10^5$  K/s were achieved in the reactor. Chars were extracted from the reactor at residence times ranging from 17 to 115 ms, spanning the conversion range of 41 to 98%.

A movable sample probe was used to collect particles at various vertical positions along the reactor, corresponding to various particle residence times. Measurements taken on the collected particles included:

- Mass loss using gravimetric analysis. This information is used to determine the overall burning rate.
- Particle size distribution using a Coulter Multisizer. This information is used to determine the decrease in particle size with mass loss.
- Apparent density using a “tap” density procedure. This information is used to determine variations in density with mass loss; and to confirm that as burning progresses, the density approaches that of ash.

Additionally, a solid particle sample was extracted just prior to devolatilization (as evidenced by the disappearance of volatile clouds surrounding the particles). The mass loss measured for these samples provides an estimate of the total volatile yields during devolatilization and information on the initial properties of the char.

### *Pressurized Thermogravimetric Analyzer*

Raw fuels, and partially converted chars taken from various locations in the entrained flow reactor, were evaluated in a pressurized thermogravimetric analyzer (PGTA) to determine reactivity (rate of mass loss as function of heating rate and atmosphere) and particle surface area.

Char reactivity was evaluated in the PGTA through gravimetric measurements of material weight change over both isothermal and transient temperature conditions. In the

isothermal tests, the material was heated at a rate of 25 K/min to the desired reaction temperature, and then the weight loss was monitored at constant temperature until combustible material was completely burned. Transient temperature tests were also used to provide additional information about the activation energy of rate controlling reactions. Reactivity testing was conducted at atmospheric pressure, and at temperature low enough ( $< 600^{\circ}\text{C}$ ) to ensure that char mass loss rates were controlled by chemical reactivity of particle with negligible influence of mass transport effects.

Surface area measurements were made at room temperature and high pressure using a  $\text{CO}_2$  gas adsorption BET method.

### **3.3.3 Results and Discussion**

#### ***Biomass Devolatilization in the LFR***

Biomass fuel burnout rate profiles are shown in Figure 9, as determined in the LFR. All biomass fuels exhibited rapid and substantial mass loss during the devolatilization. All biomass fuels produced chars that had very high extents of conversion, even at the earliest residence times. At 20 to 30 ms residence time, the particles were essentially burned out. The majority of the biomass char particles are ash. Sewage sludge had the highest yield of volatiles during devolatilization, releasing 92% of its carbonaceous material within 17 ms of exposure to the hot, flow reactor gases. Almond shells exhibited the lowest extent of mass loss, losing 37% of its carbonaceous material.

For each of the biomass types, fragmentation occurred during devolatilization at the high heating rates. Minor particle “swelling” was also exhibited during biomass devolatilization. Both fragmentation and swelling alter the size distribution of the char particles compared with the size distribution of the raw particle feed. Biomass fuel particle size distribution and apparent densities are shown as a function of residence time for the various biomass fuels in Figure 10 (almond shells), Figure 11 (rice straw), Figure 12 (wood-W), Figure 13 (wood-P), and Figure 14 (sewage sludge). As expected, the PSD narrows, the average particle size decreases, and density increases as particle residence time increases.

#### ***Char Conversion in the PTGA***

Biomass char weight loss conversion rates are shown in Figure 15. Reactivities of the biomass fuel chars taken from the LFR are shown in Table 14. When exposed to oxygen,

biomass char particles initially lose mass at a rapid rate as oxygen atoms are readily adsorbed at free carbon sites. The rate levels off as the adsorbed oxygen site fraction approaches a steady state level. The char reactivity increases rapidly to a peak, and then drops off to a steady state level.

The chars of walnut tree pruning and whole tree chips were found to have the highest reactivity to oxygen at high temperatures. The biomass chars are generally much more reactive than coal chars. Specifically, the least reactive biomass char is over 750 times more reactive than Lower Kittanning coal char. The data suggest that the higher the volatile matter of the parent material, the higher the reactivity of the char.

Biomass char reactivity decreases as they burn in a high temperature environment. This is a consequence of thermal annealing while burning.

### *Char Conversion Model*

The char conversion model can be used to accurately predict biomass behavior in high temperature environments. Agreement between model predictions and experiments is good. This suggests that the model is adequate for use at low temperatures, when the intrinsic chemical reactivity of the carbonaceous particle material controls the overall mass loss rates, as well as at high temperature, when the combined effects of pore diffusion and chemical kinetics control the overall oxidation rate.

The model indicates that as particles burn, the specific surface area of the particles increase initially, as new surface area is exposed when closed-off pores are opened, and then decreases as pores merge and coalesce as carbon is gasified. Apparent particle density decreases as the biomass char particles burn.

Accurate predictions of size and mass loss rates require that account be made for fragmentation. When account is not made for fragmentation, size distributions are not accurately modeled; specifically, particle sizes are underestimated.

At this stage of model development, the model is for use in reburn and cofiring applications. Modification of the chemical reaction mechanism to include reactions between the carbonaceous particle material with  $\text{CO}_2$ ,  $\text{H}_2\text{O}$ ,  $\text{H}_2$  and  $\text{CH}_4$  will expand the use of the model to gasification applications. Account must also be made for the fluxes of the various species to the outer surfaces of char particles. No other sub-models need modification.

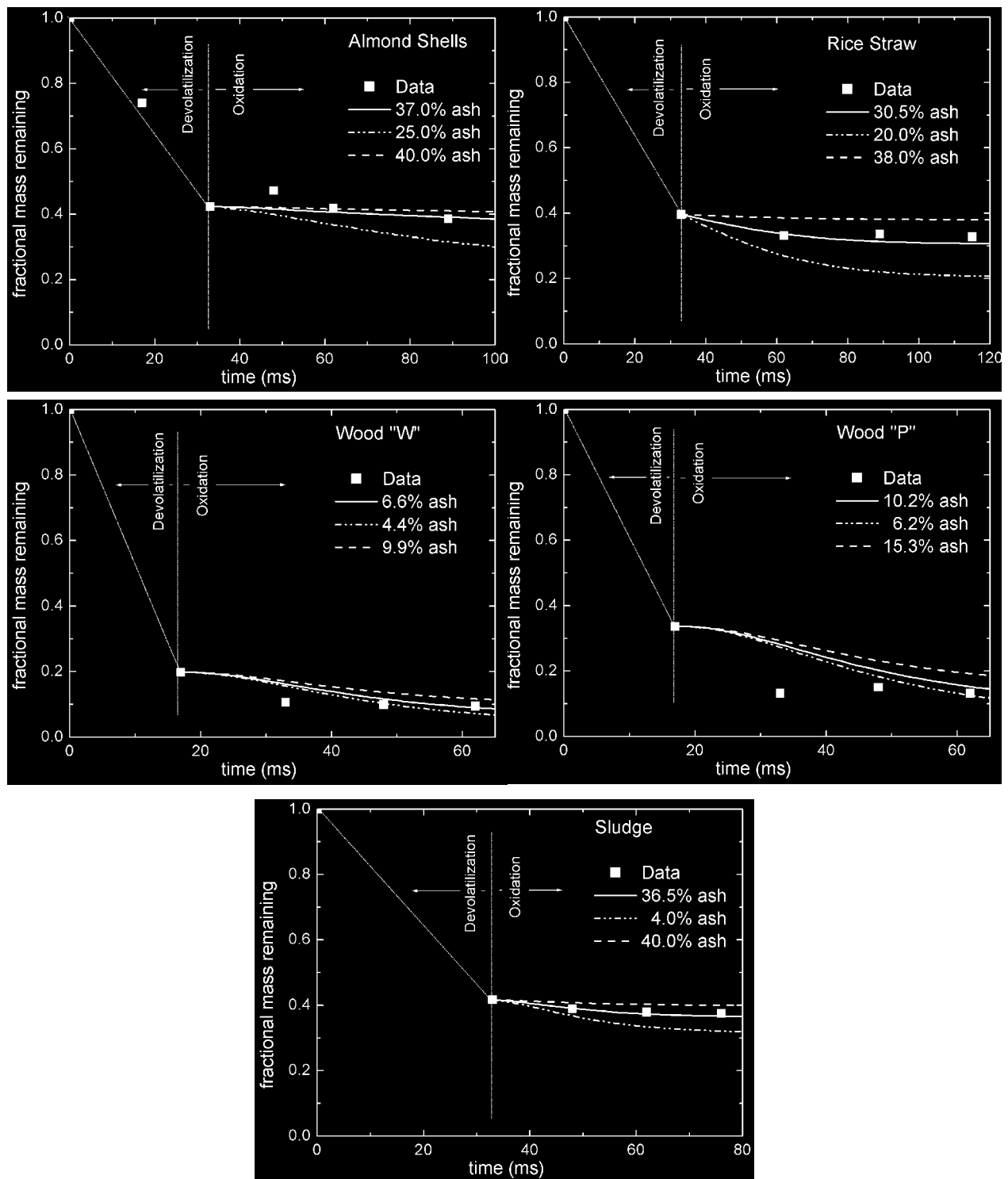
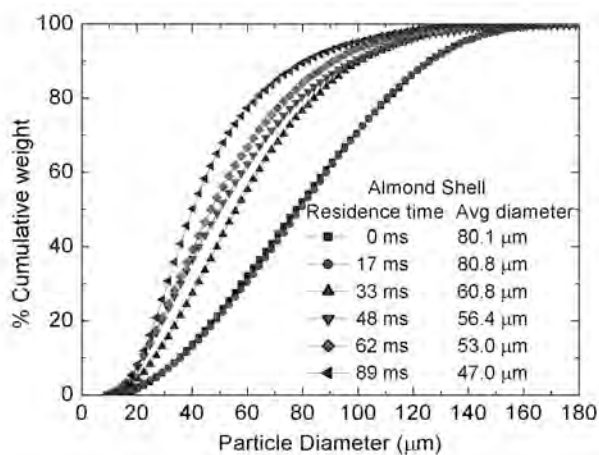
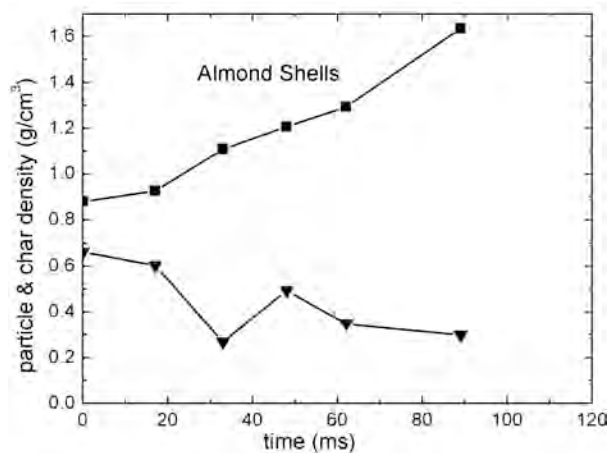


Figure 9. Comparison between measured and calculated mass remaining profiles for selected biomass fuels particles burning in 8-mol % oxygen at nominally 1243 K.

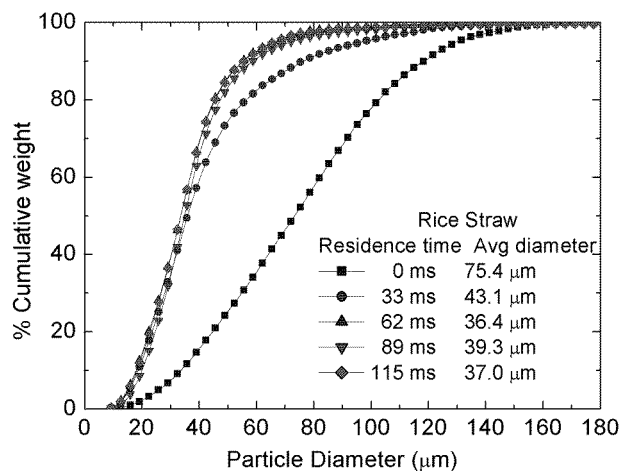


Cumulative size distribution

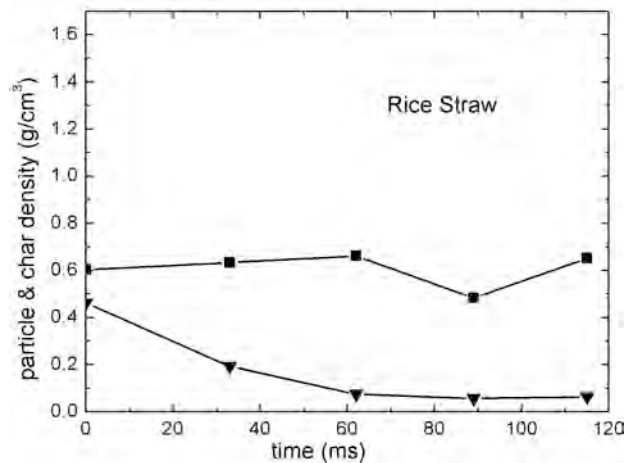


Particle (■) and char (▼) apparent densities

Figure 10. Size and apparent density distributions of almond shell particles burning in 8-mol % oxygen at 1243 K.

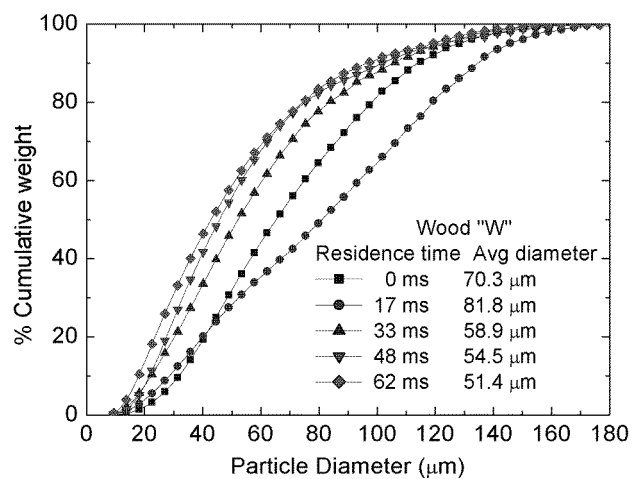


Cumulative size distribution

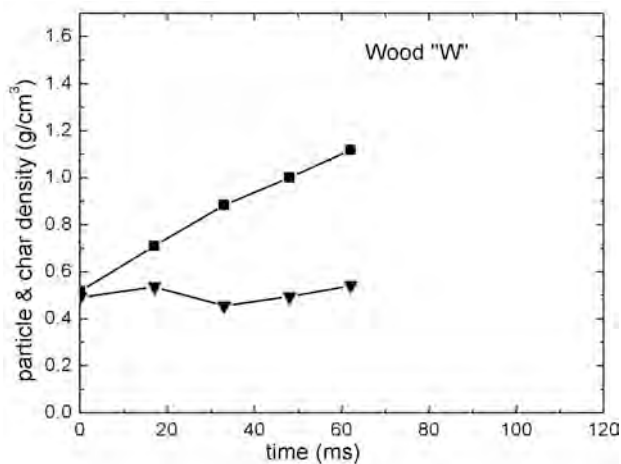


Particle (■) and char (▼) apparent densities

Figure 11. Size and apparent density distributions of rice straw particles burning in 8-mol % oxygen at 1243 K.

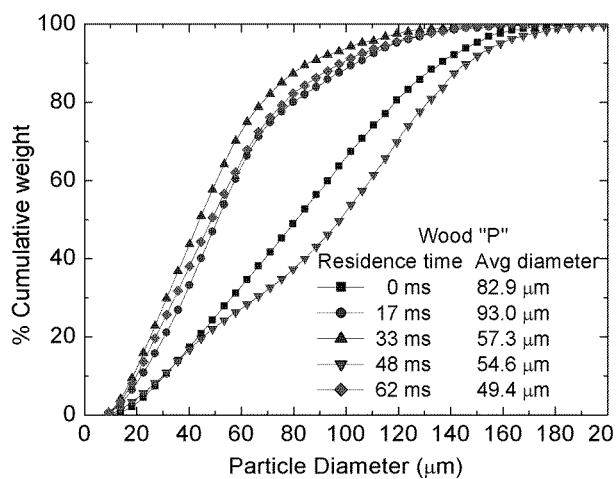


Cumulative size distribution

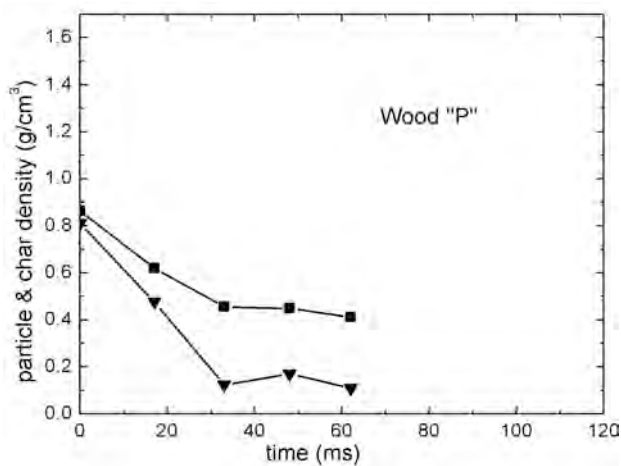


Particle (■) and char (▼) apparent densities

Figure 12. Size and apparent density distributions of wood-W (whole tree chips) char particles burning in 8-mol % oxygen at 1243 K.



Cumulative size distribution



Particle (■) and char (▼) apparent densities

Figure 13. Size and apparent density distributions of walnut tree pruning (wood-P) char-particles burning in 8-mol % oxygen at 1243 K.

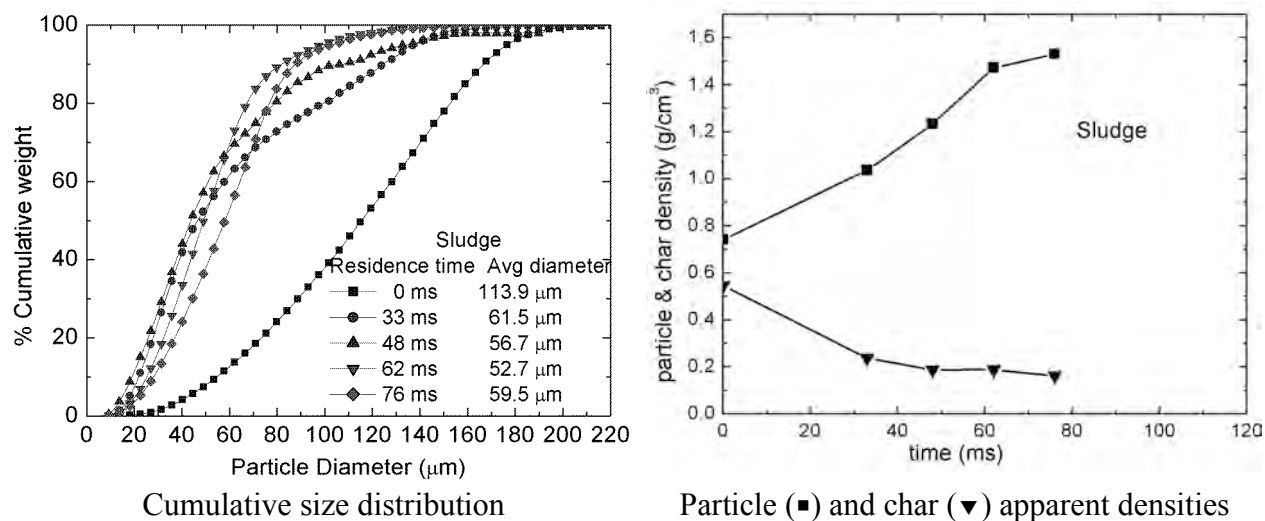


Figure 14. Size and apparent density distributions of sewage sludge particles burning in 8 mol-% oxygen at 1243 K.

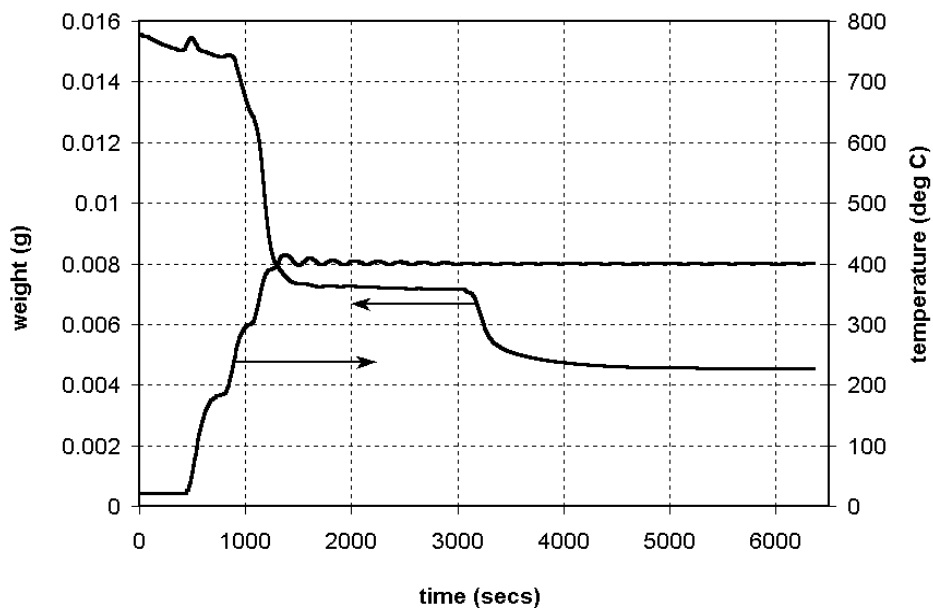


Figure 15. A typical thermogram and temperature profile measured in the PTGA. Particles are in an inert (100%  $\text{N}_2$ ) environment up to time = 3100 sec. After this time, they are exposed to an oxidizing environment. The thermogram shown is for almond shell char particles being exposed to 6 mol-%  $\text{O}_2$  at 673 K.

Table 14. Reactivities of chars burning in 8-mol % oxygen at 1243 K.

Parent Material	Sample % ash <sup>+</sup>	Peak Reactivity <sup>*</sup>	Steady-State Reactivity <sup>*</sup>	Average Reactivity <sup>*</sup>
Walnut Tree Pruning	10.2	77.97	77.97	67.32
Whole Tree Chips	6.6	72.24	72.18	65.75
Rice Straw	30.5	59.59	55.33	52.95
Sewage Sludge	36.4	29.22	28.26	26.55
Almond Shells	37.0	17.62	17.62	14.33
Lower Kittanning coal	10.0	0.023	0.017	0.018

<sup>+</sup> While heating to 1243 K at  $10^4$  -  $10^5$  K/s

<sup>\*</sup> Reactivity in  $10^{-6}$  g/m<sup>2</sup>·s

### **3.4 Pilot-Scale Cofiring / Reburning Stoker Simulation Tests Utilizing Gasified Biomass Fuels**

Reburning and cofiring tests were conducted at the GE EER Test Site using a pilot-scale boiler simulator fired with gasified biomass fuels that were selected as discussed in Section 3.1. The pilot-scale gasification-combustion tests were designed to characterize and optimize the CCG technology for application to biomass boilers. Specific objectives of these tests are to determine optimum firing mode (cofiring or reburning), to define achievable reductions in NO<sub>x</sub> and other pollutant emissions as a function of system operating variables, and to provide operating data that can be used in the design of a full-scale system. Both the way the gasifier is operated and the way in which the gasification products are added to the combustor were investigated in order to define optimum operating conditions. The CCG process involves gasifying the waste fuels in an atmospheric fluidized bed, referred to as the Hybrid fluidized Bed Gasifier (HFBG), and adding the resulting syngas to a stoker-boiler simulator called the Solid Fuels Test Facility (SFTF). The syngas is added to the SFTF either in reburning (to reduce NO<sub>x</sub> emissions) or cofiring modes.

#### **3.4.1 Experimental System**

##### *Hybrid Fluidized bed Gasifier*

Gasification was performed in a 150,000 Btu/hr Hybrid Fluidized Bed Gasifier (HFBG), as shown in Figure 16. The fluidized bed has a diameter of 10" and a height of 24". Silica sand is used as bed material. The bed material consisted of two sizes: 75% at 20 mesh, and 24% at 16 mesh. Temperature of the bed was maintained at about 1,450°F. Bed superficial velocity of about 1.5 ft/s corresponds to a bed residence time of 1.6 seconds. Pressure drop across the bed and distributor plate was about 23 and 6 inches of water, respectively. Biomass fuel was fed into a dual hopper/air lock system, and then through an auger screw conveyor into the fluidized bed. Nitrogen purge of the conveyor feeder was used to prevent backflow of syngas from the bed. Liquid petroleum Gas (LPG) was injected directly into the fluid bed for maintaining temperature. Additionally, a natural gas burner is located below the fluidized bed to supply auxiliary heat and for fluid bed warm-up. Syngas leaving the fluidized bed passes through a feedboard expansion section, and then is passed through a 4" stainless steel insulated duct directly to the SFTF for use as cofiring or reburning fuel.

The six types of selected biomass fuels were received and processed as discussed in Sections 3.1 and 3.2. Each of the fuels was processed so that they could be fed into the HFBG by the screw conveyor, as described below:

- *Almond shells* – Fed through a hammer-mill. The hammer-mill pulverized the shells to particles smaller than 1/4”.
- *Walnut pruning and whole tree wood chips* – First sent through a chipper-shredder and hammer-mill, producing sawdust like material. Because it was so light, it tended to tunnel in the feed hopper. Therefore, these fuels were pelletized (3/16”ID x 1/2” long particles) by the California Pellet Mill (CPM).
- *Non-recyclable waste paper* – Consisted of broken up fruit and vegetable cartons and essentially was cardboard reinforced with wood. This fuel was also sent through the chipper shredder and then through a hammer-mill. The fuel was difficult to process due to its heterogeneous nature and the product out of the hammer-mill had the consistency of cotton. This fuel was also pelletized by CPM.
- *Rice-straw* – A lawn mower was first used to reduce the particle size to about 1/2”. The straw was then sent to CPM where it was sent through a hammer-mill and then pelletized.
- *Municipal sewage sludge* – Dried and ground through a k-tron feeder/conveyor.

### ***Solid Fuel Test Facility***

Gasification products from the fluidized bed were routed to the Solid Fuel Test Facility (SFTF) for cofiring and reburning tests. The SFTF, shown in Figure 17, was used to simulate a biomass fired stoker boiler. The SFTF was fired at a rate of about 0.5 MM Btu/hr. A main natural gas burner is located at the end of a short horizontal barrel section (18” diameter and 9 ft long). Biomass is fed down onto a horizontal grate at the bottom of a controlled temperature tower, where it burns both in suspension and in the grate fuel bed. Air is added from the bottom of the grate. A natural gas afterburner is located above the grate. The controlled temperature tower, with diameter of 18” and height of 15 ft, is refractory lined and has two externally heated chambers that allow control of the furnace thermal conditions to simulate a full-scale boiler.

Cofiring of the syngas was performed by injecting the syngas directly above the grate and below the afterburner. Syngas combustion air was provided through the main burner. During the cofiring tests, the main burner was fired at 0.15 MMBtu/hr, the afterburner was not operated, and wood was fired at 0.35 MMBtu/hr.

Reburning was performed by injecting the syngas above the afterburner. Overfire burnout air was provided above the reburning injection location. During most of the reburning tests, the main burner was fired at 0.375 MMBtu/hr, the afterburner was fired at 0.125 MMBtu/hr, and wood was not added. Natural gas firing was mostly used during the reburning testing because it allowed for accurate and stable control of NO<sub>x</sub> levels. Limited testing with wood confirmed that natural gas only firing was able to simulate reburning performance on stoker-boiler operations. Ammonia was added to the main burner in some cases to elevate NO<sub>x</sub> to desired levels during some of the reburning tests.

### **3.4.2 Experimental Testing**

#### *Testing Series*

The general testing series is shown in Table 15. System shakedown testing was used initially to determine baseline system operating conditions. The first test series was used to establish the reburn performance of the SFTF. Liquid Propane Gas (LPG) was used as reburning fuel and injected directly into the SFTF. The SFTF was fired with natural gas only, and with wood only. The HFBG was not operated.

In the second test series, the use of gasified almond shells in both reburning and cofiring modes was evaluated. Reburning was done with both wood chips and gas-only main firing modes. Test series three was used to evaluate the reburning performance using syngas generated from other biomass fuel types. The main furnace was fired with natural gas only. In test series four, cofiring of syngas generated from other biomass fuel types was assessed. Wood chips were used as the primary fuel. Test series five was used to determine optimum basic reburning capabilities. In test series six, Advanced Reburning (AR) was evaluated. In test series seven, boiler tube slagging and fouling was assessed (as will be discussed in Section 3.5).

#### *Measurements*

The HFBG and SFTF were equipped with instrumentation to measure gas flow rates, temperatures, pressures, feed rates, and other parameters necessary to verify system operability and provide information on test conditions. A continuous emissions monitoring system was used to measure NO<sub>x</sub>, CO, CO<sub>2</sub>, CH<sub>4</sub>, and O<sub>2</sub> at both the exit of the SFTF and the exit of the HFBG. Bag samples of HFBG gasification products were collected for detailed analysis using gas

chromatography/mass spectrometry for hydrocarbons, H<sub>2</sub>, etc. Biomass fuel analyses results were taken from that conducted by U.C. Davis in the laboratory scale gasification tests.

### ***System Operating Conditions***

Typical operating conditions for the hybrid-fluidized bed are shown in Table 16. Typical operating conditions for the SFTF are shown in Table 17. Biomass fuel heat input was varied between 3 and 20% of the total system heat input. Overfire air rate was adjusted so that the overall stoichiometric ratio was approximately 1.25.

## **3.4.3 Results and Discussion**

### ***HFBG Syngas Composition and Bed Operation***

Figure 18 compares HFGB syngas composition for the various biomass fuels at a SR of 0.3. The HFGB temperature was around 1,430°F. The relative levels of CO, H<sub>2</sub>, and HCs in the syngas are a function of the SR, bed temperature, and fuel composition. Generally, the syngas bulk compositions are very similar at the same SR. Fuels with higher carbon content produced syngas with generally higher levels of CO. Composition of the syngas as a function of the biomass feedrate is shown in Figure 19 for almond shells. This corresponded to a SR of between 0.29 and 0.96. As the SR decreases, the syngas content of CO, H<sub>2</sub>, and other hydrocarbons increases. Syngas heating value is shown in Figure 20 as a function of SR.

After several runs of operating with the same sand batch, HFGB bed agglomeration occurred with the use of almonds shells and rice straw. Alkali compounds in the biomass ash, such as sodium and potassium, react with sand and form heavy and sticky silicates. Large pieces of fused materials were discovered in the HFGB after the bed was cleaned out.

### ***LPG Reburning***

LPG reburning tests were performed to determine the effect of the primary fuel on reburning performance. Uncontrolled initial NO<sub>x</sub> levels (NO<sub>i</sub>) were controlled by adding NH<sub>3</sub> to the main burner, and ranged from 150 to 300 ppmv. Both natural gas only, and wood/gas mixtures (70% wood, 30% gas) were used in the primary flame.

Figure 21 shows LPG reburning performance results. NO<sub>x</sub> reduction increased as the reburn heat input increased. This is similar to the extensive, well-documented performance with natural gas reburning. The LPG reburning performance was similar to that expected based on the

reburn temperature that was used. Better performance would be expected at higher reburning temperatures.

### ***Biomass Basic Reburning***

Biomass reburning was evaluated in the SFTF at a reburn injection temperature of 2,150°F. Overfire air was injected at about 1,850°F, which produced a reburn zone residence time of about 800 ms. Figure 22 shows NO<sub>x</sub> reduction as a function of reburn heat input for the selected biomass fuels, except for sewage sludge results which will be shown later, at a NO<sub>i</sub> of 300 ppmv. For comparison, reburn performance using LPG is also shown. Reburning performance increases with the initial increase in reburn heat input for all fuels. With the exception of non-recyclable waste paper, reburning performance dips (peaks) at about 15% heat input. This dip is directly related to biomass fuel nitrogen content. Fuel nitrogen produces nitrogenous species such as ammonia and hydrogen cyanide in the gasification products. These nitrogen containing species form NO in the presence of excess oxygen supplied by the overfire air. The high nitrogen fuels, almond shells and rice straw, have a large reduction, while no dip is observed for the low nitrogen containing non-recyclable waste paper.

To illustrate the impact of fuel nitrogen on reburning, Figure 23 shows reburning performance at 20% reburn heat input as a function of biomass fuel nitrogen content. This figure illustrates that NO<sub>x</sub> reduction is directly related to fuel nitrogen content. Modeling work, which will be discussed in Section 3.6, confirmed that the fuel nitrogen is primarily responsible for the decrease in reburning performance.

Figure 24 shows reburning performance for a lower NO<sub>i</sub> of 100 ppmv. Reburning performance was not as good at this lower NO<sub>i</sub> level. Only non-recyclable waste paper produced positive NO<sub>x</sub> reductions. The fuel nitrogen impact is more pronounced at lower NO<sub>i</sub> levels.

Municipal sewage sludge reburning test results are shown in Figure 25 and Figure 26 corresponding to NO<sub>i</sub> levels of 100 and 300 ppmv, respectively. For NO<sub>i</sub> at 100 ppmv, the NO level increased drastically as reburn heat input was increased. A 20% reburning with gasified sewage sludge resulted in a 400% increase in NO levels. The performance was slightly better when initial NO levels were higher. For a NO<sub>i</sub> of 300 ppmv, 25% NO reduction was achieved at 8% reburning. However, as reburning heat input increased beyond this level, NO emissions began increasing due to the high 3.81% nitrogen content of the sewage sludge fuel. These tests

demonstrate that gasified sewage sludge with high-N content cannot provide significant NO<sub>x</sub> control under typical reburning conditions.

### *Optimized Basic Reburning*

Modeling was conducted to understand the reburning behavior of gasified biomass products and explore operating parameters that would optimize reburning performance, particularly for gasified high-N fuels such as almond shells and sewage sludge. Details of the modeling set-up and results are presented later in Section 3.6. The modeling results demonstrated that the NO<sub>x</sub> reduction efficiency increased with an increase in reburning fuel injection temperature for fuels with low fuel-N (such as non-recyclable waste paper) and increased with a decrease in the injection temperature for fuels with high fuel-N content (such as almond shells and sewage sludge). The optimum temperature for NO<sub>x</sub> control generally depends on the composition of gasification products and on the composition and temperature of the flue gas at the point of reburning fuel injection. Modeling predictions (which were verified by experimental data) suggested that the optimum NO<sub>x</sub> reduction conditions for biomass fuels with high fuel-N content were at 5 - 10% reburning fuel heat input and a temperature of about 982°C (1800°F) in the reburning zone.

Based on modeling results, reburning tests were conducted to validate model predictions and demonstrate improved NO<sub>x</sub> control performance. For low nitrogen containing non-recyclable waste paper, optimized tests were conducted at a higher reburn temperature of 2,348°F and overfire air temperature of 2,042°F and a reburn fuel heat input of 20% (compared with initial testing at a reburn temperature of 2,151°F). NO<sub>x</sub> reductions increased by about 5% as a result of reburning temperature increase.

For high nitrogen containing almond shells and sewage sludge, optimized tests were conducted at a lower reburning temperature of 1,826°F and 1,840°F, respectively (compared with initial testing at a reburn temperature of 2,151°F). Figure 27 compares the reburning results for almond shells. Optimum NO<sub>x</sub> reductions of 65% was achieved at 8 – 10% reburning fuel heat input at the reburning temperature of 1,827°F, compared with an optimum NO<sub>x</sub> reduction of 45% at a 10 – 15% heat input and reburning temperature of 2,151°F.

Figure 28 compares the reburning results for sewage sludge. NO<sub>x</sub> reductions of 53% were achieved at the 1,840°F and a heat input of 8%, compared with NO<sub>x</sub> reductions of 25% at the higher reburn temperature of 2,100°F.

### *Advanced Reburning*

Advanced Reburning (AR) tests were conducted with high nitrogen fuels (almond shells and sewage sludge) to address the impact of the addition of urea and sodium promoters (sodium carbonate was added to a urea solution) on NO<sub>x</sub> reduction efficiency.

Figure 29 shows results of AR with almond shells and a urea/sodium solution, at a reburn fuel input rate of 10%. About 90% NO<sub>x</sub> reduction was achieved. For these tests, the urea (or urea/sodium, or sodium only) was injected into the rich zone (between the reburning fuel injection and overfire air injection locations), the NH<sub>3</sub>/NO<sub>i</sub> ratio was about 1.5, and the NaCO<sub>3</sub> concentration was 100 ppmv in the flue gas. Injecting sodium by itself (without urea) provided over 80% efficiency. Nitrogen and alkalis present in biomass fuels inherently promote the reburning process.

AR tests with sewage sludge syngas were also conducted (Figure 30). The reburn fuel injection temperature was 2,100°F, with urea injection into the rich zone at a temperature of 1,900°F. With urea only, reburning provided 60% NO<sub>x</sub> reduction. With urea and sodium promoter, 70% NO<sub>x</sub> reduction was achieved. The tests were conducted at 8% reburning fuel heat input, with a NO<sub>i</sub> of 280 ppmv, and an overfire air (OFA) temperature of 1,680°F.

Further AR tests were conducted with sewage sludge with a lower reburning injection temperature of 1,840°F, and injection of urea and sodium promoter into the lean zone with the OFA at a temperature of 1,680°F (Figure 31). NO<sub>x</sub> reduction was increased to 84%. Note that even at this low reburn fuel injection temperature, CO emissions were low, averaging about 4 ppmv in the exhaust gas.

Another series of AR tests were conducted with the sewage sludge syngas to study the impact of varying sodium concentrations (10 ppm to 100 ppm) on the AR performance. Results from these tests are summarized in Figure 32 and indicate that, while also injecting urea, an injected sodium concentration as low as 30-40 ppm is sufficient to obtain optimum performance.

### *Cofiring*

Cofiring tests were conducted with the SFTF fired at 500,000 Btu/hr with 70% of the heat input coming from wood chips. The cofiring fuel was injected into the SFTF at 2,250°F. Combustion air for the gasified fuel was added in the horizontal barrel section.

The initial (baseline) NO levels (NO<sub>i</sub>) in the SFTF averaged about 150 ppm for the various fuels. This initial level is measured when the SFTF is burning wood and the gasifier is

connected to the SFTF but without gasification products yet. At this point, only flue gas from heating-up the fluidized bed is injected into the SFTF, which does not represent heat input into the system.

Figure 33 shows NO emissions as a function of cofiring heat input for all of the fuels tested except sewage sludge. Note that almond shells NO emissions for the entire cofiring heat input range is much higher than the rest of the fuels. This is because the oxidant for the natural gas in the gasifier was air rather than CO<sub>2</sub> during this almond shells cofiring experiment. This in turn added an additional baseline NO emission that is not due to biomass burning. The oxidant for the natural gas in the gasifier was then changed to CO<sub>2</sub> for all other fuels/tests. The almond shells NO emission in the cofiring mode is expected to behave similar to rice straw because of their comparable fuel nitrogen content. In general for other fuels, NO levels increased with increasing biomass feed rate, particularly for fuels with high nitrogen content. The least effect was seen with non-recyclable waste paper (low fuel nitrogen) where NO emissions varied by +/- 6% while the most effect was seen for rice straw (high fuel nitrogen) at 20% cofiring which resulted in approximately 35% increase in NO.

NO<sub>x</sub> emissions results from cofiring sewage sludge gasification syngas is shown in Figure 34. The primary fuel for these tests was natural gas, and baseline NO emissions were approximately 180 ppm (0% O<sub>2</sub>). Results indicate that NO emissions rise with increased heat input due to the high N content of the gasified sewage sludge.

### ***Comparison Between Biomass Cofiring and Reburning Methods***

Cofiring and reburning methods were compared relative to their impact on NO<sub>x</sub> emissions. Cofiring tests for the various fuels corresponded to an average NO<sub>i</sub> of about 150 ppm (the approximate baseline NO emission when firing wood in the SFTF). Reburning performance was compared to cofiring performance at this cofiring baseline at selected biomass syngas heat inputs. Since reburning tests were conducted at 100 and 300 ppm NO<sub>i</sub> levels, reburning performance at NO<sub>i</sub> = 150 ppm was estimated by linear interpolation from the two tested data points corresponding to NO<sub>i</sub> of 100 and 300 ppm. The comparison was conducted at syngas heat input of 14% for almond shells, rice straw, and wood “W”, and 20% for non-recyclable waste paper. These heat inputs represent the optimum reburning performance for these fuels. As shown in Figure 35, for all of the selected cases, reburning provides lower NO emissions compared to cofiring, with an approximate reduced emission of 15% for rice straw, 29% for non-recyclable

waste paper, 17% for wood “W”, and 10% for almond shells. Improvement percentages increase as fuel nitrogen decreases for the fuels tested (see fuel nitrogen content impact in Figure 23). Wood “P” could not be compared since only one reburning experiment was conducted at 300 ppm NO<sub>i</sub>.

#### **3.4.4 Summary and Conclusions**

Experimental and modeling results suggest that optimum conditions in the reburning zone are different for fuels with high and low fuel-N content. Typically, [1,2] the reburning fuel is injected at reburn flame temperature ( $T_{RF}$ ) of 2240-3140°F, and the efficiency of NO<sub>x</sub> reduction increases with an increase in  $T_{RF}$ . The efficiency of NO<sub>x</sub> reduction also usually increases with an increase in the amount of the reburning fuel [3,4] at reburning fuel heat inputs up to approximately 20%. Further increases in the amount of reburning fuel either have no impact or result in a small decrease in the efficiency of NO<sub>x</sub> reduction.

For fuels with high fuel-N content, the optimum conditions in the reburning zone are found to include lower reburning fuel injection temperatures and reburning heat inputs than those found for natural gas and other fuels with low fuel-N content. The optimum conditions for NO<sub>x</sub> reduction by gasification products generated by high-N content fuels were found to correspond to  $T_{RF}$  close to 982°C (1800°F) and 8-10% reburning fuel heat input.

During this study utilizing various biomass fuels at initial NO<sub>x</sub> of ~ 300 ppmv, it was found that conventional reburning can achieve up to 40% of NO<sub>x</sub> reduction, low-temperature reburning can achieve up to 65% NO<sub>x</sub> reduction at 5-10% reburn heat input, and AR can achieve up to 90% NO<sub>x</sub> reduction.

Results presented in this work were obtained at an overfire air temperature ( $T_{OFA}$ ) in the range of 1700-2060°F, while OFA is typically injected in the temperature range of 2060-2780°F to achieve complete oxidation of reburning fuel. At all tests conditions, the CO concentration in the flue gas at the SFTF exit was below 10 ppmv. It was possible to achieve such low CO concentrations in combustion products at low  $T_{OFA}$  because the reburning fuel was a gas.

To conclude, experimental and modeling results confirm that the CCG technology shows promise in reducing NO<sub>x</sub> emissions from biomass boilers while using low-cost waste biomass.

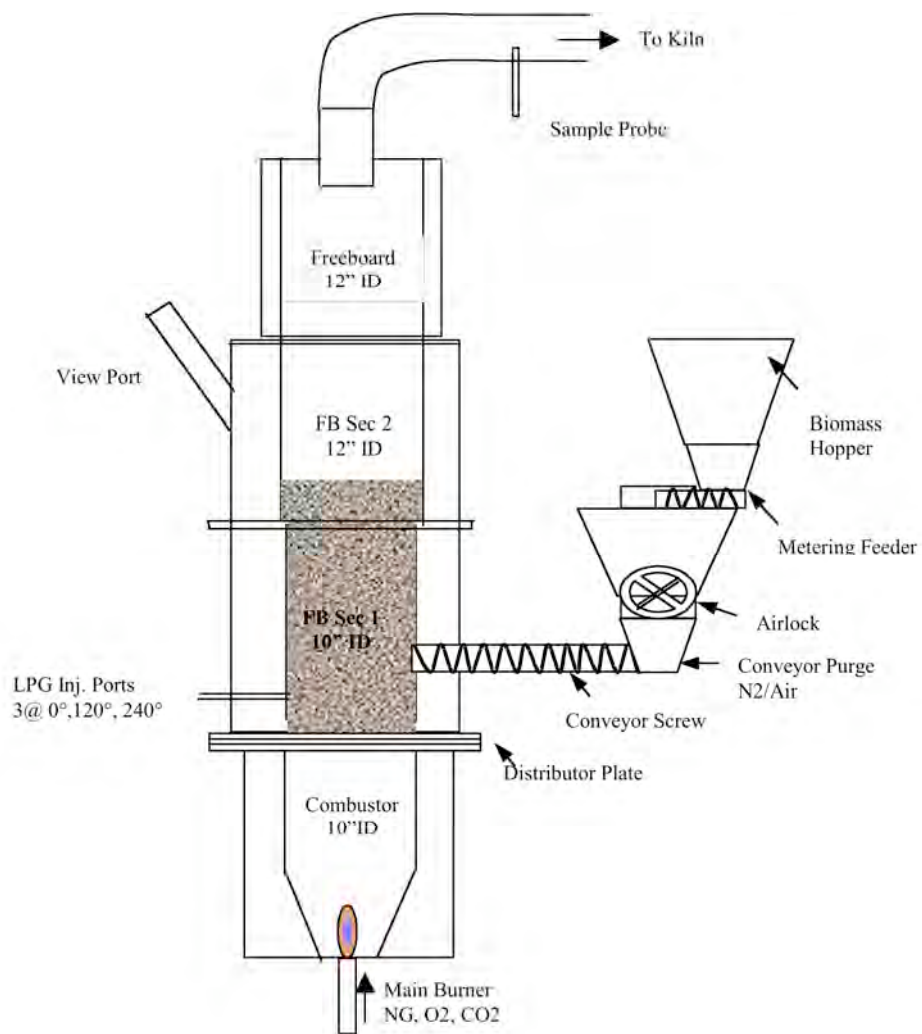


Figure 16. Hybrid Fluidized Bed Gasifier (HFBG).

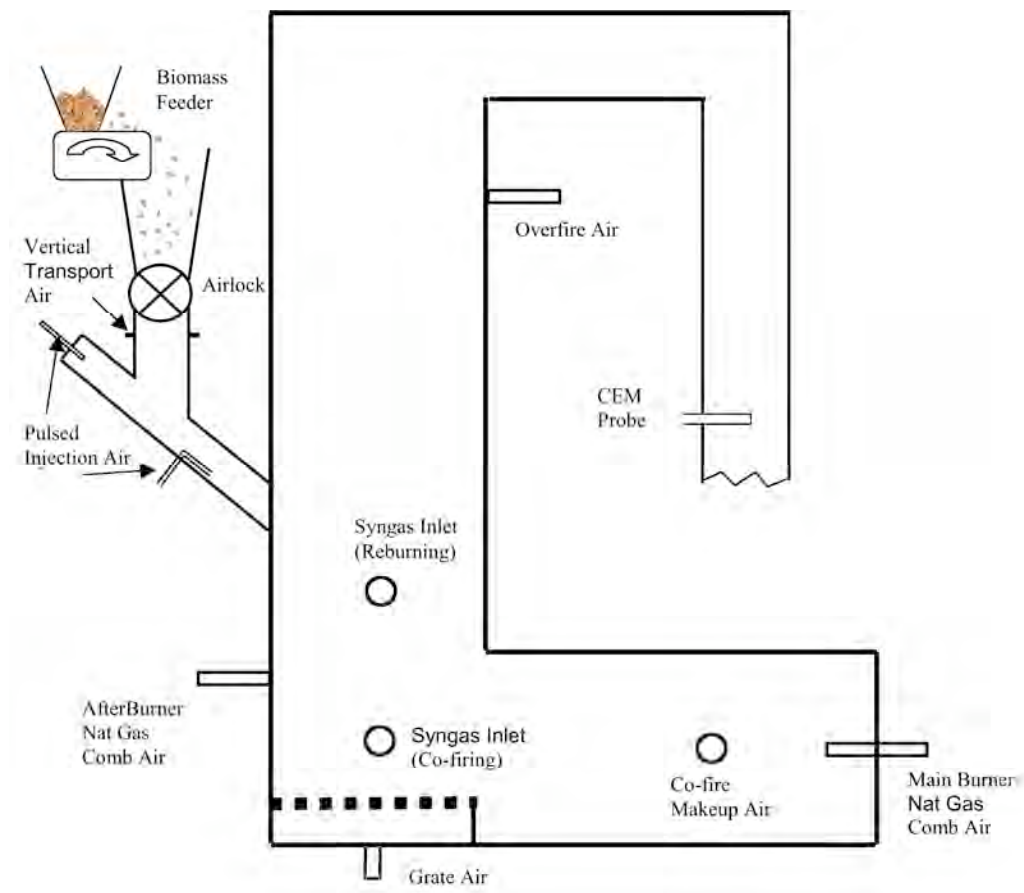


Figure 17. Solid Fuels Test Facility (SFTF).

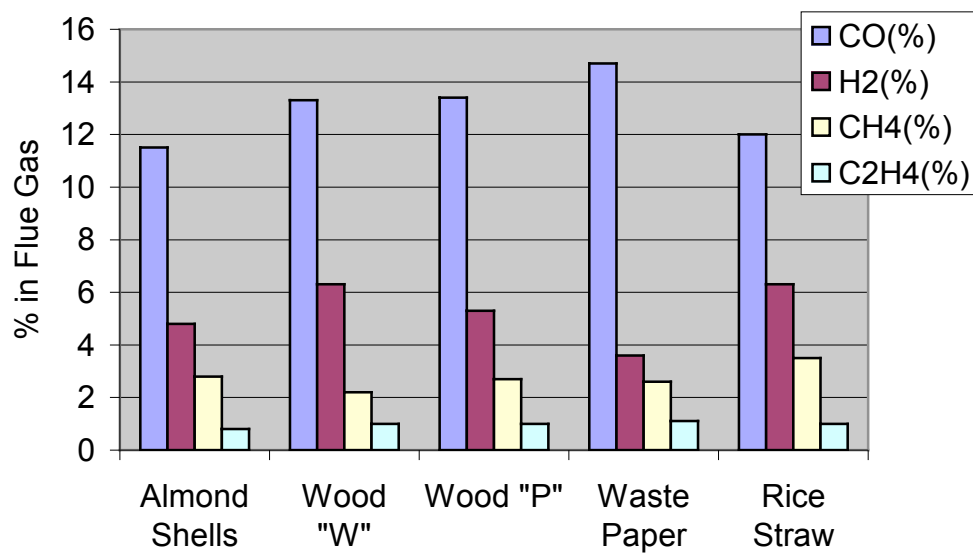


Figure 18. Synthesis gas composition of various biomass fuels at SR= ~0.3.

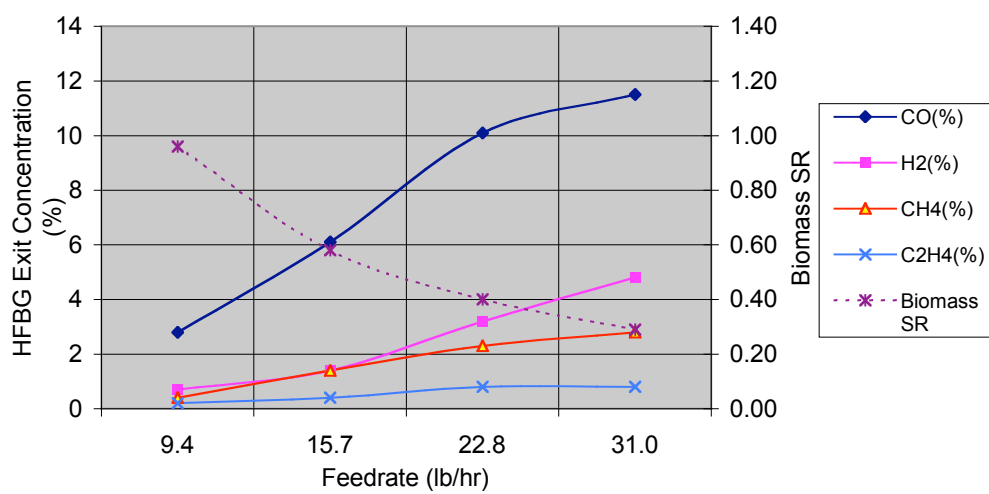


Figure 19. Almond shells gasification products.

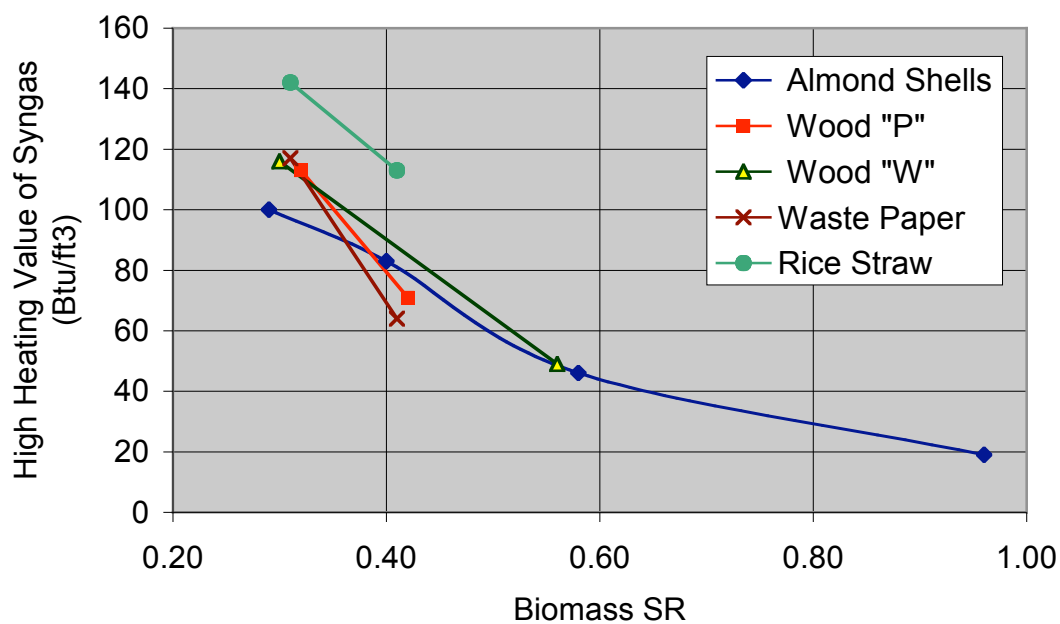


Figure 20. Heating value of gasification products.

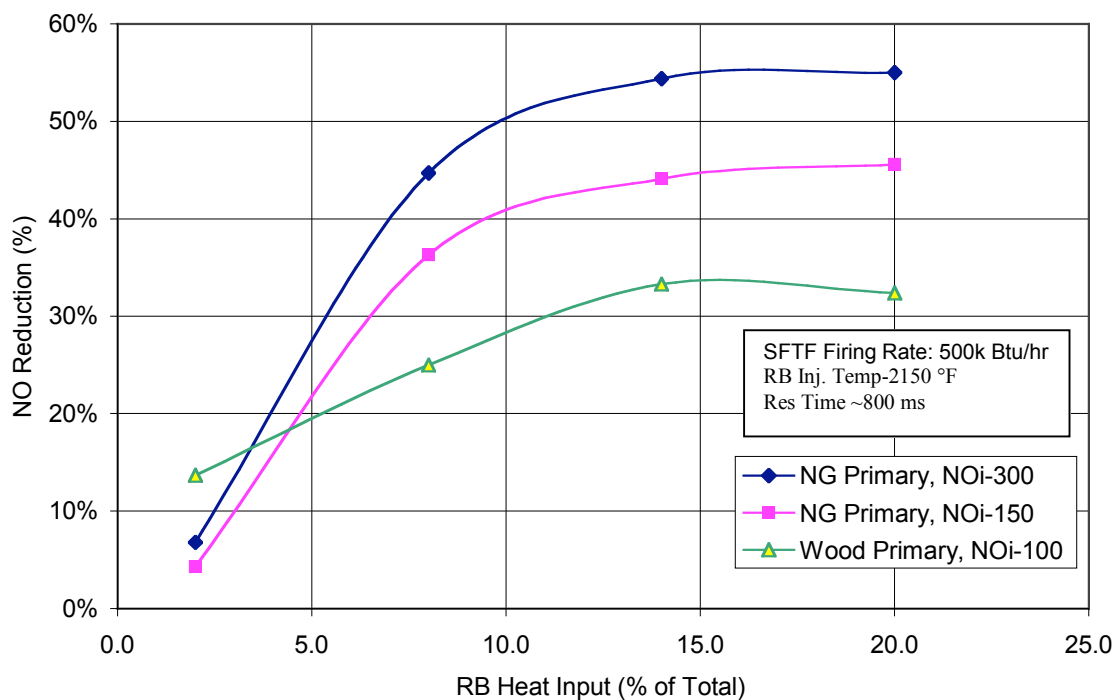


Figure 21. Reburning performance of Liquid Petroleum Gas (LPG) at various  $NO_i$  in SFTF.

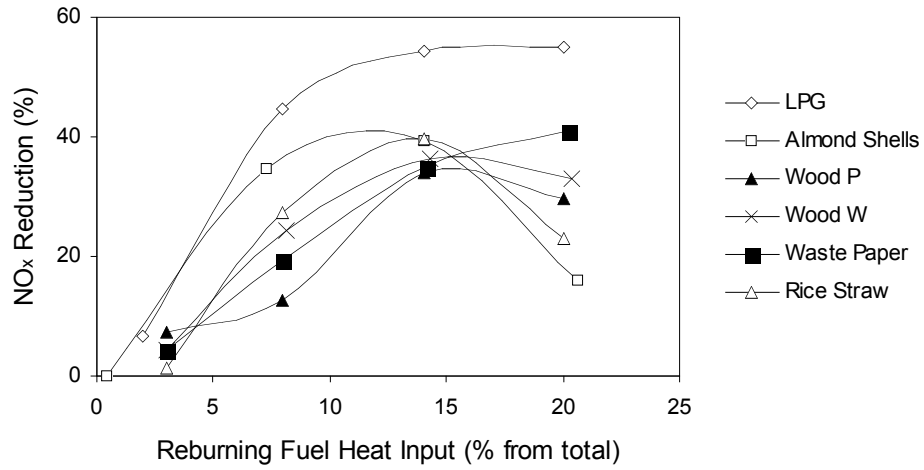


Figure 22. Reburning performance of LPG and gasified biomass products at  $\text{NO}_i = 300$  ppmv.

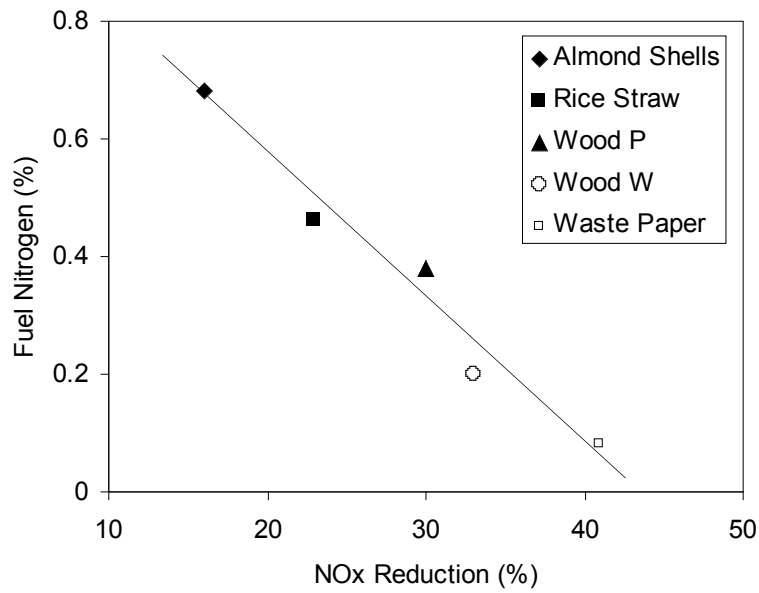


Figure 23. Correlation for  $\text{NO}_x$  reduction and fuel-N at 20% biomass syngas heat input.

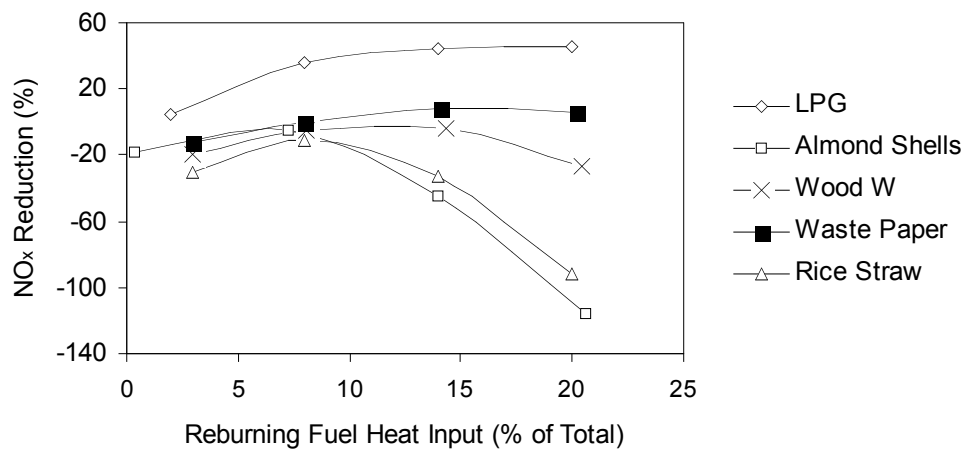


Figure 24. Reburning performance of gasified biomass products at NO<sub>i</sub> = 100 ppm.

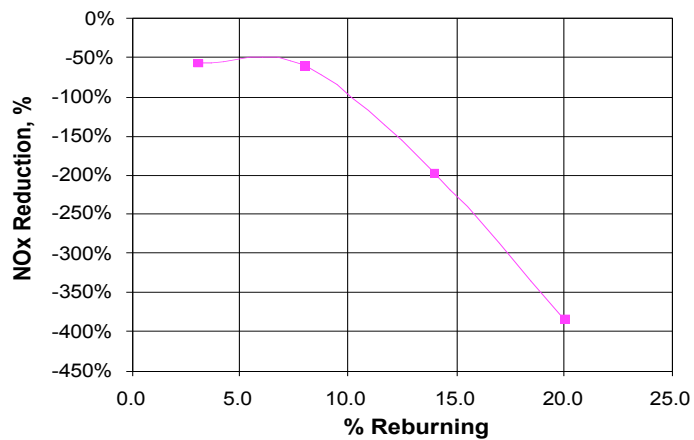


Figure 25. Reburning performance of gasified MSS (NO<sub>i</sub> = 100 ppm).

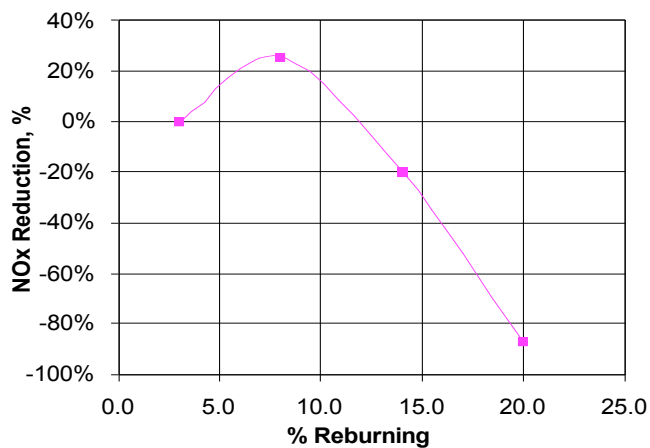


Figure 26. Reburning performance of gasified MSS (NO<sub>i</sub> = 300 ppmv).

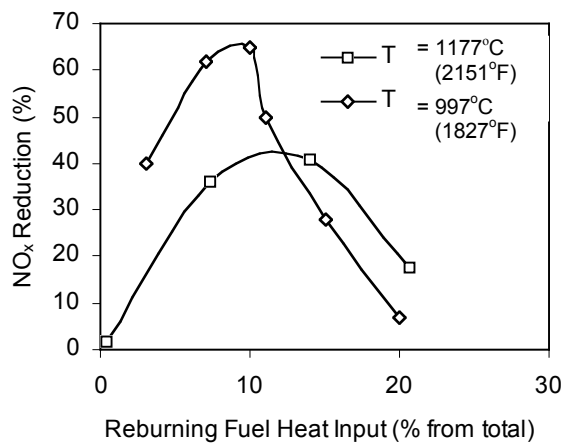


Figure 27. Almond shells reburning experimental data at 2151°F and 1827°F.

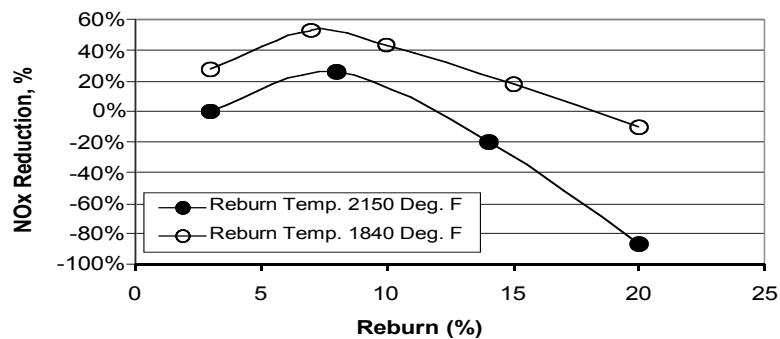


Figure 28. Impact of reburning fuel injection temperature on HFBG gasified MSS reburning performance (NO<sub>i</sub>=270 ppmv @ 0% O<sub>2</sub>).

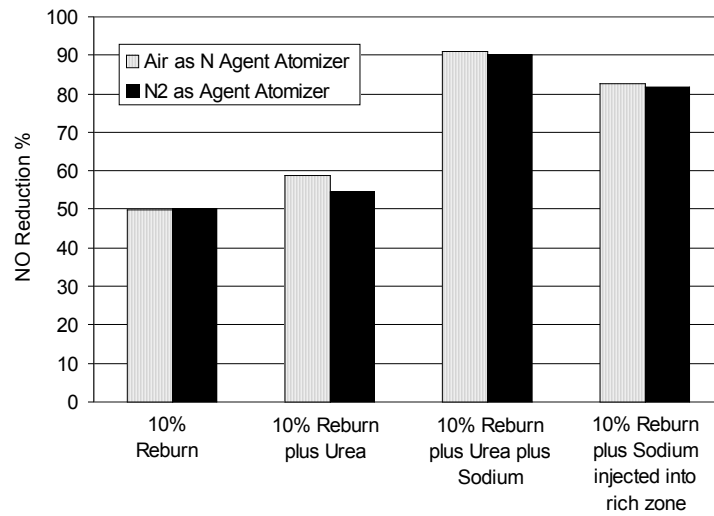


Figure 29. Advanced Reburning (AR) with almond shells syngas at high reburn temperature.

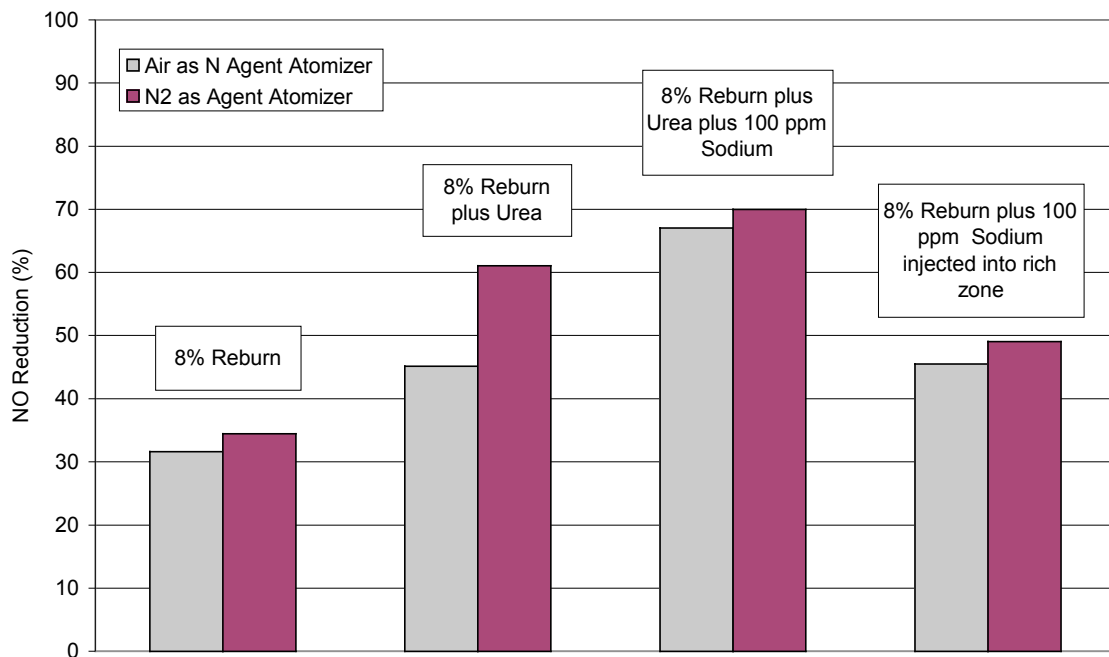


Figure 30. Advanced reburning (AR-Rich) with MSS syngas at high reburning fuel injection temperature (reburn fuel at 2100°F, urea/sodium at 1900°F and OFA at 1680°F,  $\text{NO}_i = 280$  ppmv, and urea and sodium injected into the rich zone).

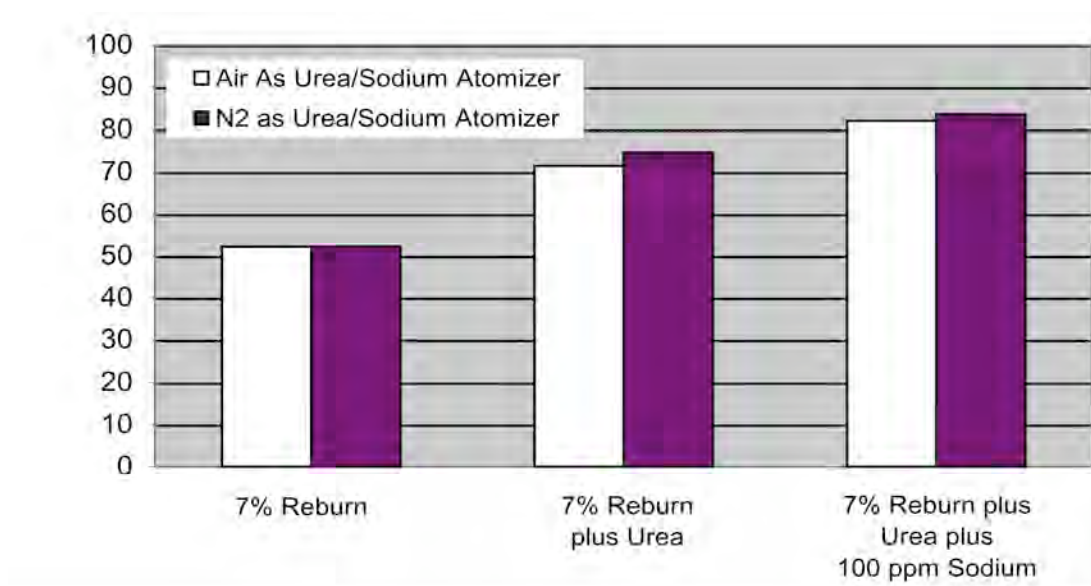


Figure 31. Advanced reburning with MSS syngas at low reburn fuel injection temperature (reburn fuel at 1840°F, urea/sodium injected at 1680°F with OFA).

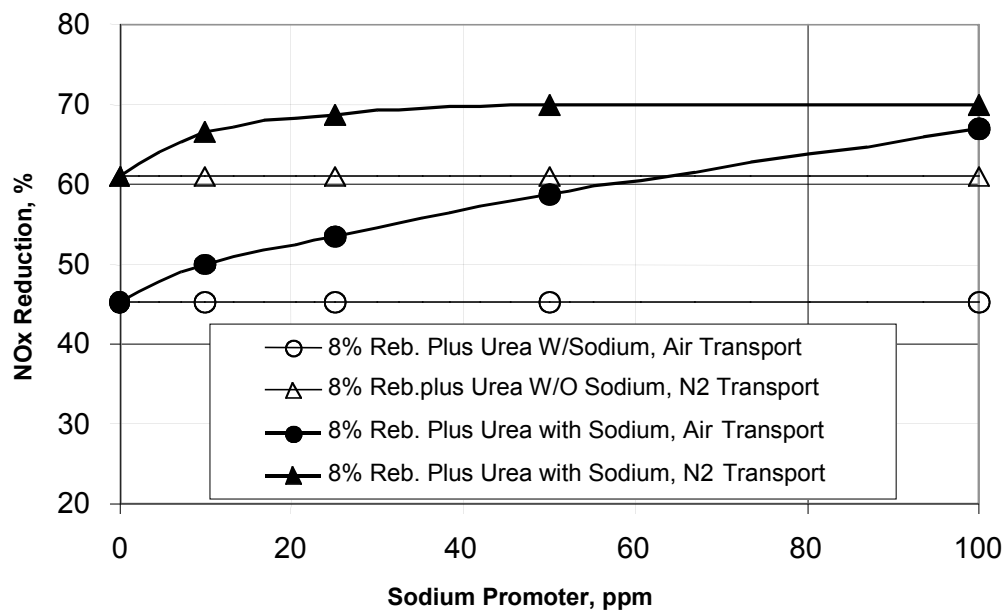


Figure 32. Advanced reburning with MSS syngas (reburning fuel at 2100°F, OFA at 1680°F, urea/sodium at 1900°F,  $\text{NO}_i = 280 \text{ ppmv @ } 0\% \text{ O}_2$ ).

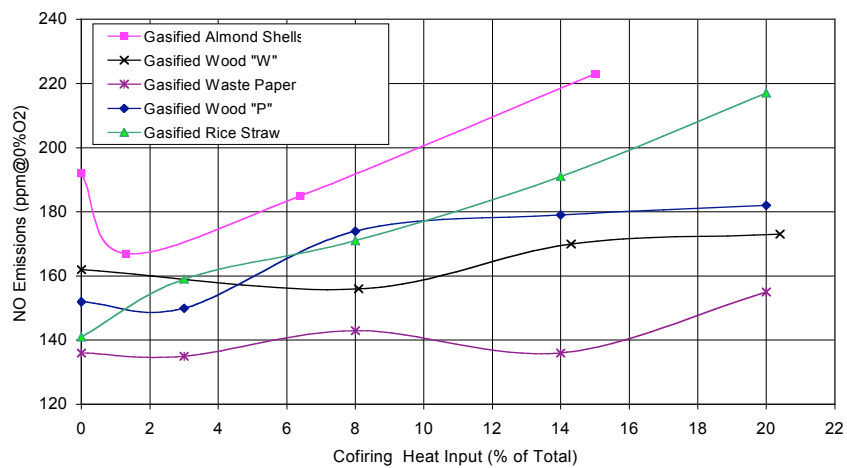


Figure 33. Impact of syngas cofiring on NO emissions.

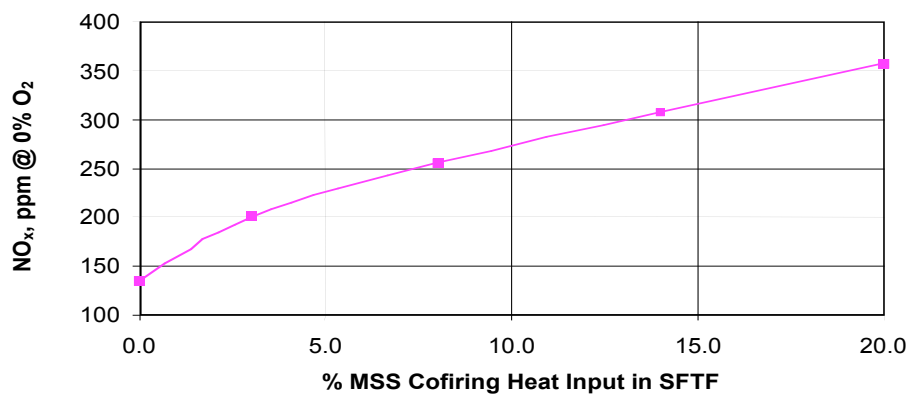


Figure 34. NO emissions with gasified municipal sewage sludge co-firing.

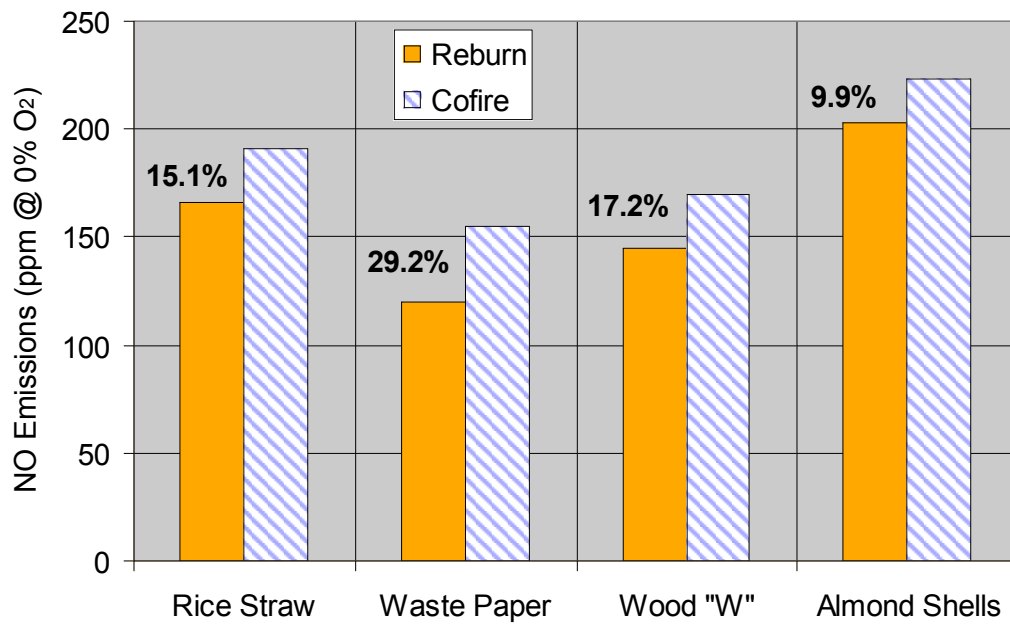


Figure 35. Comparison Between Biomass Syngas Cofiring and Reburning (*Reburn/Cofire at 20% for waste paper and 14% for other fuels*)

Table 15. Test matrix for gasification and reburning / cofiring tests.

Series	Main Fuel	Mode	Cofiring Fuel	NOi (ppmv @ 0% O2)	Biomass Type	Biomass SR	Exit SR	Heat I/p to SFTF	N Agent	N-agent Injection Temp. (F)
1. Performance Verification Tests										
1.1	Nat. Gas <sup>a</sup>	Reburning	LP Gas	150,300	n/a	n/a	n/a	3-20%	None	
1.2	Wood Chips <sup>b</sup>	Reburning	LP Gas	~100	n/a	n/a	n/a	3-20%	None	
2. Parametric Tests with Almond Shells										
2.1	Nat. Gas	Reburning	Syngas	100, 300	Almond shells	0.3-0.8	0.50-0.95	3-20%	None	
2.2	Wood Chips	Reburning	Syngas	~100	Almond shells	0.3-0.8	0.50-0.95	3-20%	None	
2.3	Wood Chips	Co-firing	Syngas	n/a	Almond shells	0.3-0.8	0.50-0.95	3-20%	None	
3. Biomass Reburning Fuel Screening Tests										
3.1	Nat. Gas	Reburning	Syngas	100, 300	Wood chips	0.3-0.8	0.50-0.95	3-20%	None	
3.2	Nat. Gas	Reburning	Syngas	300	Pruning	0.3-0.8	0.50-0.95	3-20%	None	
3.3	Nat. Gas	Reburning	Syngas	100, 300	Rice straw	0.3-0.8	0.50-0.95	3-20%	None	
3.4	Nat. Gas	Reburning	Syngas	100, 300	Waste paper	0.3-0.8	0.50-0.95	3-20%	None	
3.5	Nat. Gas	Reburning	Syngas	100, 300	Sewage Sludge	0.3-0.8	0.50-0.95	3-20%	None	
4. Biomass Co-firing Fuel Screening Tests										
4.1	Wood Chips	Co-firing	Syngas	n/a	Wood chips	0.3-0.8	0.50-0.95	3-20%	None	
4.2	Wood Chips	Co-firing	Syngas	n/a	Pruning	0.3-0.8	0.50-0.95	3-20%	None	
4.3	Wood Chips	Co-firing	Syngas	n/a	Rice straw	0.3-0.8	0.50-0.95	3-20%	None	
4.4	Wood Chips	Co-firing	Syngas	n/a	Waste paper	0.3-0.8	0.50-0.95	3-20%	None	
4.5	Wood Chips	Co-firing	Syngas	n/a	Sewage Sludge	0.3-0.8	0.50-0.95	3-20%	None	
5. Optimized Basic RB Tests										
5.1	Nat. Gas	Reburning	Syngas	TBD	TBD	TBD	TBD	TBD	None	
6. Advanced Reburning Tests										
6.1	Nat. Gas	Reburning	Syngas	300	Optimum	Optimum	Optimum	Optimum	Urea	TBD
7. Slagging and Fouling Tests (Will be performed in Task 2.6)										
7.1	Wood Chips	n/a	none	n/a				20%	None	
7.2	Wood Chips	Co-firing	Syngas	n/a	TBD		TBD	20%	None	

Table 16. Operating conditions for the HFBG.

		<u>Gasification</u>	<u>Overnight</u>
Nat Gas	Btu/hr	97,000	97,000
Combustion Air	scfm	0	16.8
CO2	scfm	4.79	0
Press. Purge Air	scfm	1.5	1.5
O2 Enrichment	scfm	4.78	4.78
Conveyer Purge	scfm	2.66(N2)	2.66(Air)
Biomass	lb/hr	8-30	8-30

Table 17. Operating conditions for the SFTF.

		<u>RB</u>	<u>Co-fire</u>	<u>Overnight</u>
Main Burner Gas	Btu/hr	375,000	150,000	350,000
Main Burner Air	Scfm	58.2	32.9	66.1
Make up air (main burner)	Scfm	14.9	0	0
Afterburner Gas	Btu/hr	125,000	0	100,000
Afterburner Air	Scfm	21.5	0	20.7
Grate Air	Scfm	0	8.3	0
Wood	Btu/hr	0	350,000	0
Biomass Vertical Transport Air	scfm	0	8.7	0
BM Transport Sootblower Air	scfm	0	38.7	0
Pulsed Air	scfm	0	2.1	0
Co-firing Make up Air	scfm	0	12-24	0
Overfire Air	scfm	12-24	0	0
SFTF Exit SR	scfm	1.25	1.25	1.12

### **3.5 *Fouling / Slagging and Byproduct Emissions***

The impact of biomass fuel cofiring and reburning applications on boiler fouling and slagging tendencies and byproduct emissions (focusing on trace organics and metals emissions) was evaluated. In particular, studies were performed to analyze how biomass slag collects on the water walls and how fouling deposits accumulate at tube surfaces such as in the superheater, reheater, and economizer.

#### **3.5.1 Slagging and Fouling Experimental System and Testing Procedures**

Testing was performed to evaluate the impact of biomass cofiring and reburning on boiler slagging and fouling tendencies. Testing was conducted using GE EER's pilot-scale gasifier/stoker boiler simulator set-up, described in detail in Section 3.4. The tests were designed to characterize and compare furnace slagging deposits, convective pass fouling deposits, and the related effects of these deposits on heat transfer under two operating modes: straight biomass firing (as a baseline) and waste gasification cofiring. In each mode, the combustor was operated at a steady state for 8 hours. Water-cooled panels were installed in the furnace to characterize slagging deposits and air-cooled probe banks were installed in the convective pass to characterize fouling deposits. Temperatures to and from the panels and probes were measured throughout the test run, allowing the impacts of ash deposition on heat transfer to be quantified. The slagging panel was installed in the flame zone at flue gas temperatures of 2,100-2,300°F. One fouling probe was installed at a flue gas temperature of 1,700-1,800°F. Another fouling probe was installed at a flue gas temperature of 1,400-1,450°F. A third fouling probe was installed at a flue gas temperature of 1,000-1,100°F. After each run, the slagging and fouling deposits were recovered and slagging/fouling differences between straight biomass firing and waste gasification cofiring/reburning were then identified.

Woodchips fuel was used as the baseline primary fuel. Two of the opportunity biomass fuels were used: (1) walnut pruning, and (2) municipal sewage sludge. The sewage sludge was cofired by premixing the sewage sludge particles with the woodchips before they were fed into the stoker-boiler simulator. The walnut pruning fuel was first gasified and then the gasification product was cofired in the stoker boiler simulator. In each of these cases, opportunity biomass fuel cofiring contributed to ~ 10% of the total system heat input.

### **3.5.2 Slagging and Fouling Experimental Results**

Figure 36 and Figure 37 compare fouling factors and heat absorption for baseline woodchip only firing and walnut pruning syngas cofiring. Figure 38 and Figure 39 compare fouling factors and heat absorption for baseline woodchip only firing and sewage sludge cofiring. Cofiring of gasified sewage sludge or walnut pruning did not significantly affect the slagging or fouling characteristics of the boiler. Generally, the biomass cofiring produced lower levels of fouling and slagging compared to that from firing coal.

Walnut pruning syngas cofiring produced lower fouling in the post flame zone and convective pass than the sewage sludge cofiring. Alternatively, cofiring of walnut pruning syngas generated higher fouling at the economizer section due to fine fly ash particles that form due to condensation on downstream cool surfaces. Municipal sewage sludge generates a heavier ash that tends to remain on the grate.

None of the tests generated significant amounts of slagging or fouling deposits. Deposits were generally light and easy to remove. The biomass cofiring cases did not cause any significant increase in ash deposition. Pictures of fouling and slagging deposits taken after the termination of the fouling and slagging experiment confirm that the deposits are very minimal. For comparison, in previous tests with coal and wood, deposits up to an inch thick or more on the fouling probes for high-fouling fuels have been observed. For the biomass-cofiring test, deposit thickness at the various probe/coupon locations appeared to be in the order of one mm or less.

Table 18 summarizes the deposit characteristics during the fouling and slagging experiments. Ash deposited on the grate from woodchips burning had a light brown color and light density. Ash on the grate from sewage sludge cofiring test had mixed red and light brown color, and a higher density. The sewage sludge has high ash content and the residual ash had a powdery, metal-like appearance. In a physical test, the sewage sludge generated a red ash with higher density than that of woodchips ash density, and that was not soluble in water.

### **3.5.3 By-Product Emissions Evaluation**

Experimental tests as well as an intensive literature search were performed to explore the impacts of gasifying/burning biomass fuels on harmful by-product emissions, including polychlorinated dioxins and furans (PCDD/PCDF) and trace metals.

### ***Impact of Cofiring Biomass on PCDD/PCDF Emissions***

Numerous recent testing programs indicate that various types of biomass (including sewage sludge, wood, straw, and grass) can be readily cofired with coal in stoker, pulverized coal, or fluidized bed arrangements, and that combustion quality or PCDD/PCDF emissions are not impacted by the addition of biomass to coal combustion. The addition of biomass to coal (or biomass) boilers likely results in similar or lower PCDD/PCDF emissions compared with coal- or biomass-only combustion because:

- Many types of biomass have high S/Cl ratio, or either very low levels of either S or Cl. PCDD/PCDF formation tends to decrease as the S/Cl ratio increases.
- Biomass cofiring does not impact combustion efficiency in well-designed and operated systems (CO and HC levels are not increased with biomass combustion).
- Biomass will typically have lower levels of catalytic metals such as Cu and Ni compared with coal.

PCDD/PCDF emissions are expected to be reduced by the supplemental use of gasified biomass as either cofiring or reburning fuel in biomass primary fuel fired boilers due to:

- *Higher combustion efficiency* – Combustion of biomass gasifier producer gas in the main boiler is more efficient and complete than the direct combustion of the solid biomass or coal in the main boiler.
- *Retention of ash in gasifier* – The gasifier will retain ash that may potentially contain catalytic metals. The ash loading in the main boiler will be lower when using the gasifier compared to boiler operation without the gasifier.

### ***Impact of Cofiring Biomass on Trace Metals Emissions***

The cofiring of biomass fuels in coal- or biomass-fired boilers is not expected to adversely impact boiler trace metals emissions. The metals content of biomass streams ranges widely depending on the biomass type. For example, wood generally has extremely low levels of trace metals such as arsenic, cadmium, lead, chromium, and mercury, whereas, sewage sludge can have much higher levels of these metals. In any case, semi- and non-volatile metals such as chromium, arsenic, lead, and cadmium are controlled at extremely high efficiency (> 99.9%) with conventional ESPs or baghouses, which are typically used on all coal or biomass-fired boilers. Additionally, the presence of low- and semi-volatile metals in biomass fuels will not increase these metals emissions from boilers when these fuels are utilized in the CCG (i.e., the

biomass is first gasified and then cofired in the boiler) because these metals would primarily remain in the bottom ash of the gasifier and would not partition to the syngas.

Highly volatile metals, primarily mercury, can be present in sewage sludge at levels that are 10 to 20 times higher than that of coal and other biomass fuels. Mercury is extremely volatile but can be controlled in coal- and biomass-fired boiler ESPs and baghouses, likely from adsorption onto fly ash contained unburned carbon. Alternative mercury control techniques are also available. Mercury can be controlled in wet scrubbers (absorption in the scrubber liquor), which are commonly used on coal-fired and certain wood-fired boilers.

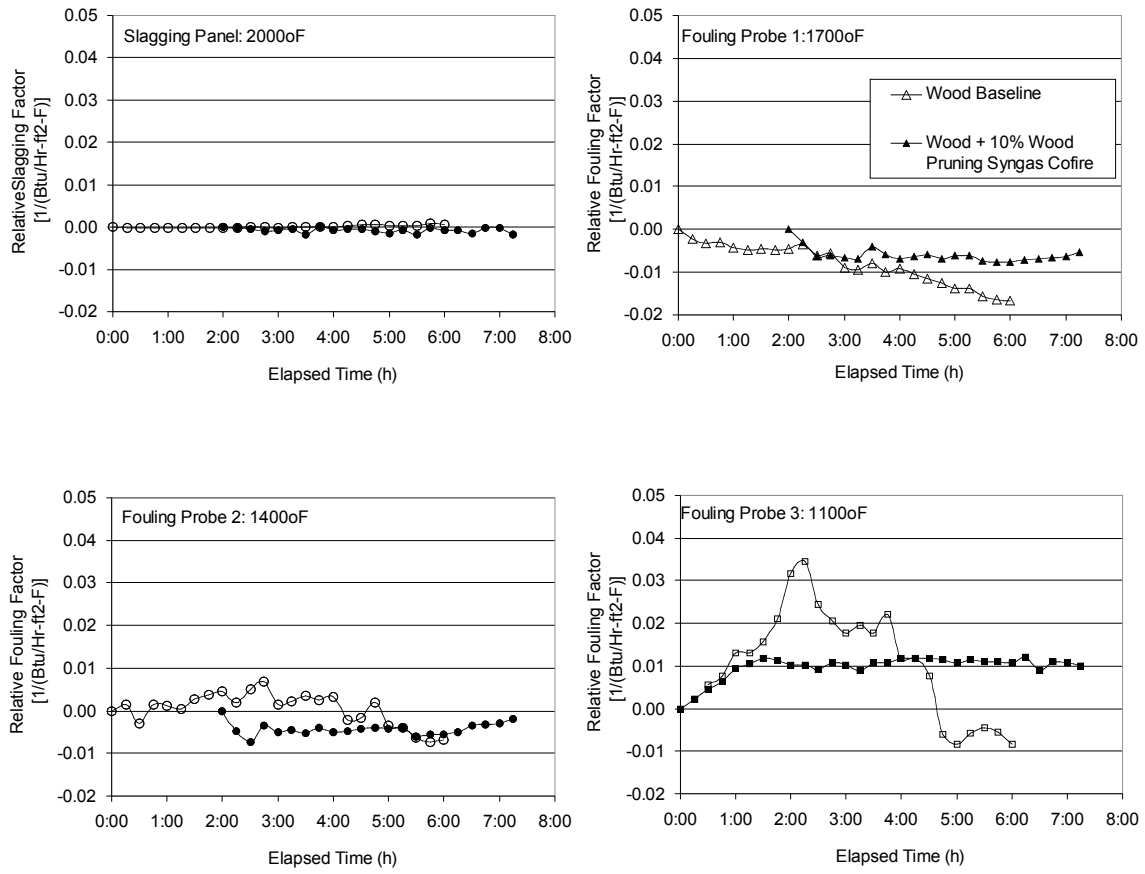


Figure 36. Relative fouling factors for woodchips baseline and woodchips firing plus 10% cofiring of Wood “P” syngas.

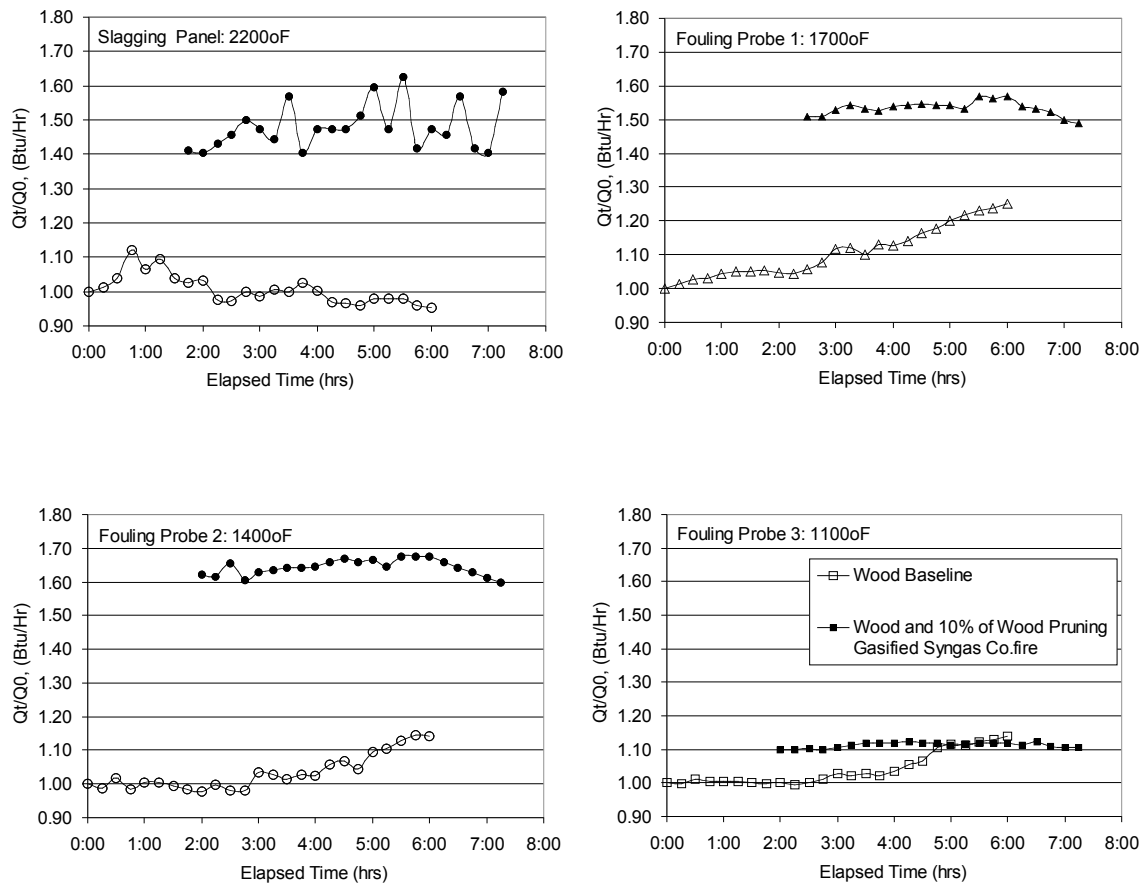


Figure 37. Relative heat absorptions for woodchips baseline and woodchips firing plus 10% cofiring of Wood “P” syngas.

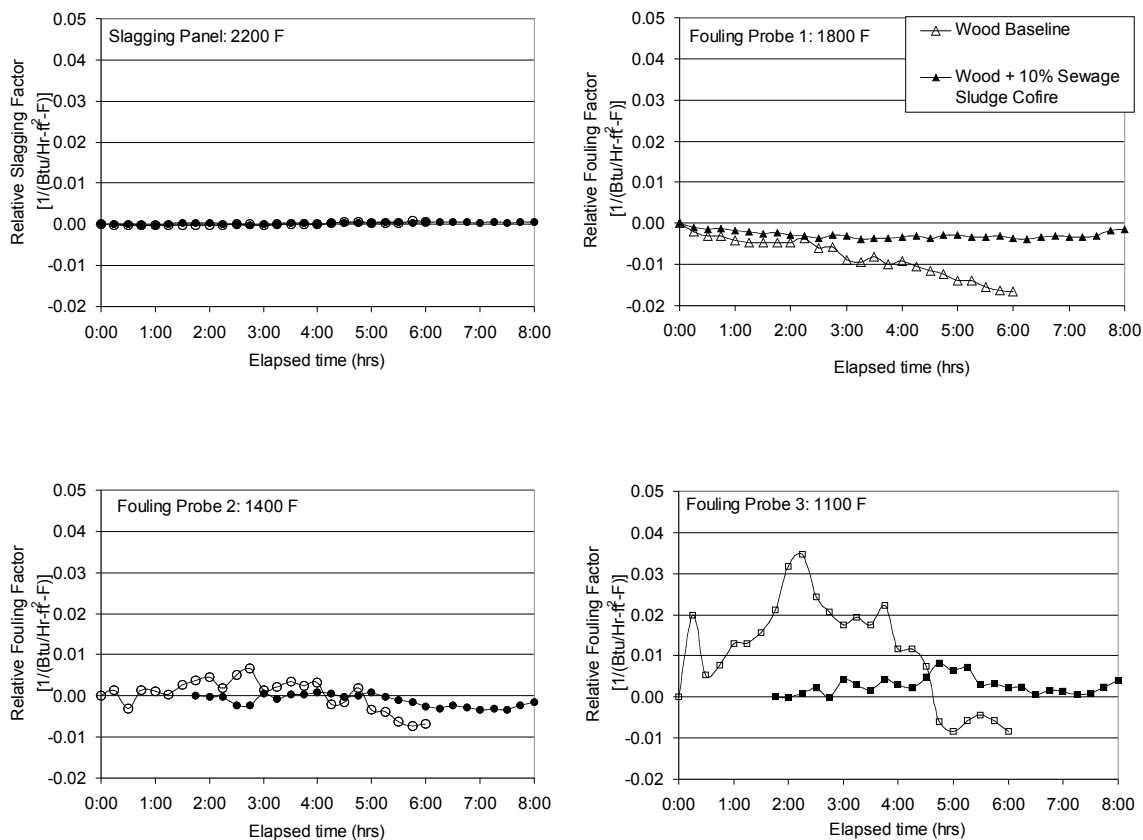


Figure 38. Relative fouling factors for woodchips baseline and woodchips firing plus 10% cofiring of municipal sewage sludge syngas.

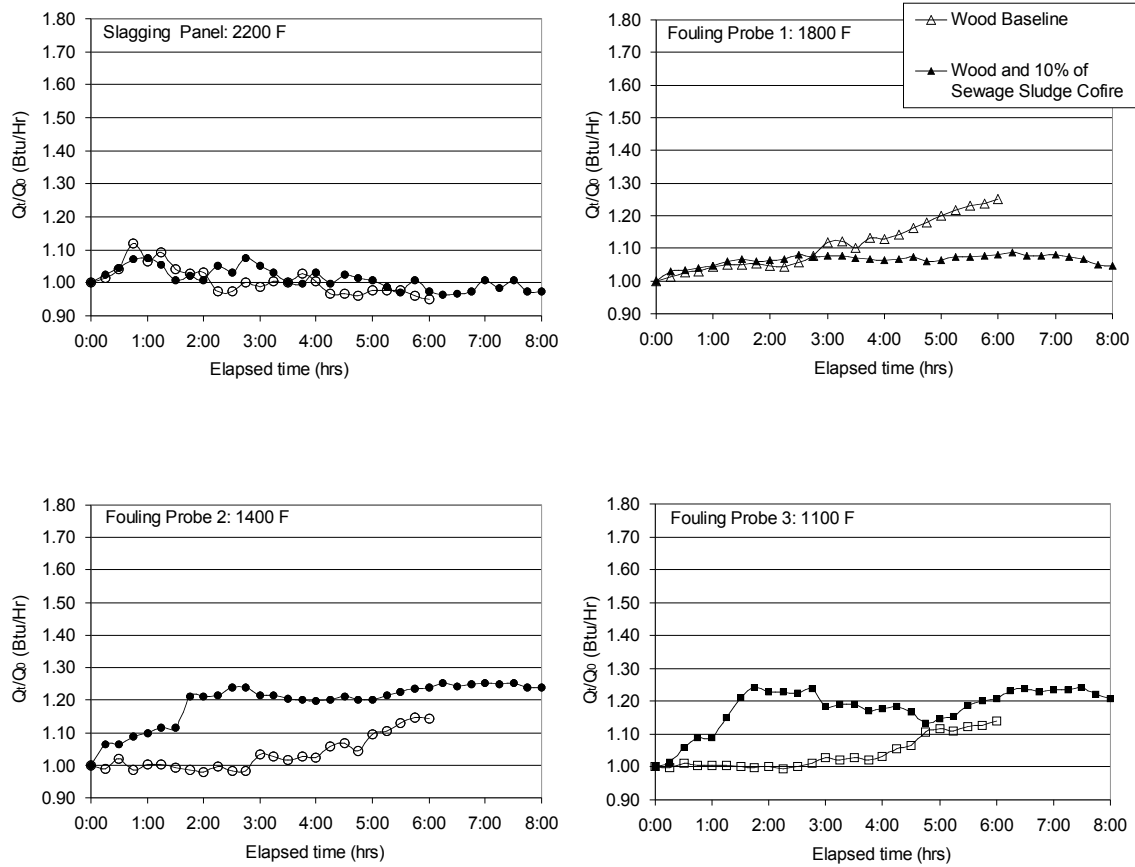


Figure 39. Relative heat absorptions for woodchips baseline and woodchips firing plus 10% cofiring of municipal sewage sludge syngas.

Table 18. Deposit characteristics for slagging and fouling experiments.

Test Condition	Test Piece	Deposit color	Deposit characteristics	Deposit mass (g)
Woodchips baseline	Slagging Coupon	Black	Looks like Smoke deposited.	< 0.45
Woodchips baseline	Fouling Probe 1	Black-Brown	Flaky, low-density, easy to remove	< 0.45
Woodchips baseline	Fouling Probe 2	Black-Brown	Flaky, low-density, easy to remove	< 0.45
Woodchips baseline	Fouling Probe 3	Black-Brown	Flaky, low-density, easy to remove	< 0.45
Woodchips -9% MSS	Slagging Coupon	Black-some red	Looks like Smoke deposited.	< 0.45
Woodchips -9% MSS	Fouling Probe 1	Black-Brown-some red	Flaky, low-density, easy to remove	< 0.8
Woodchips -9% MSS	Fouling Probe 2	Black-Brown	Flaky, low-density, easy to remove	< 0.45
Woodchips -9% MSS	Fouling Probe 3	Black-Brown	Flaky, low-density, easy to remove	< 0.45
Woodchips -9% MSS	Slagging Coupon	Black	Looks like Smoke deposited.	< 0.45
Woodchips -9% MSS	Fouling Probe 1	Black-Brown	Flaky, low-density, easy to remove	< 1
Woodchips -9% MSS	Fouling Probe 2	Black-Brown	Flaky, low-density, easy to remove	< 1
Woodchips -9% MSS	Fouling Probe 3	Black-Brown	Flaky, low-density, easy to remove	< 2

### **3.6 Process and Kinetic Modeling**

Kinetic and process modeling was performed to analyze the behavior of and optimize conditions for firing biomass as a reburning and cofiring fuel in biomass boilers. Initial modeling studies were performed analyzing basic reburning  $\text{NO}_x$  reduction potential using various biomass-reburning fuels. The next step was to optimize reburning performance by varying operating conditions within the model. Once optimum conditions were established, reburning was analyzed using biomass gasification products as reburning fuel. Advanced Reburning (AR) behavior, where promoters such as ammonia and sodium are used, was also analyzed using the same kinetic modeling technique.

#### **3.6.1 Modeling Procedure**

##### *Reburning Chemistry Mixing Model*

The reburning chemistry-mixing model (RCMM) includes a combination of a detailed kinetic mechanism with a simplified representation of mixing, and utilizes well stirred and plug-flow reactors to describe processes that occur in the boiler. The characteristic feature of RCMM is utilization of an integrated approach to describe the reburning process. The RCMM approach includes: (1) evaluation of mixing characteristics of the combustion facility under investigation using a model of a single jet in crossflow, (2) utilization of plug-flow reactors to describe processes that occur in the boiler, (3) the distributed addition of reagents, and (4) the inverse mixing approach. The mixing is described by using the Zwietering approach where the secondary stream is distributed along the primary stream in a continuous fashion over a certain period of time. It is assumed that the products composition, except for  $\text{NO}_x$ , exiting the primary combustion zone corresponds to equilibrium conditions at the experimental temperature. These equilibrium values were found using the NASA CET93 code, which is often used to calculate adiabatic flame temperatures and equilibrium compositions of combustion products. The kinetic mechanism used in the RCMM to describe natural gas reburning included 447 reactions of 65 C-H-O-N gas phase species. A “One Dimensional Flame” (ODF) chemical kinetic code was employed to model the experimental data. The ODF treats a system as a series of one-dimensional reactors. Each reactor may be perfectly mixed (well-stirred) or unmixed (plug-flow). Each ODF reactor may be assigned a variety of thermodynamic characteristics, including adiabatic, isothermal, or specified profiles of temperature or heat flux, and/or pressure.

### *Model Calibration, Validation, and Bench Mark Comparisons*

Modeling of natural gas and LPG reburning demonstrated good agreement with experimental data. Figure 40 shows comparison between RCMM predictions and experimental data for natural gas reburning. The RCMM correctly describes the reburning efficiency at different amounts of the reburning fuel. Figure 41 shows good agreement between experimental data and modeling predictions for LPG reburning.

### **3.6.2 Results and Discussion**

#### *Initial Modeling of Almond Shells Reburning*

RCMM was applied to reburning with almond shells gasification products. Initial  $\text{NO}_x$  was 300 ppm. Figure 42 presents comparison between modeling predictions and experimental data. Modeling disagreed with experimental data. Major disagreements between modeling and experiments included (1) higher maximum efficiency of  $\text{NO}_x$  reduction predicted by modeling than that observed in experiments, (2) modeling predicted that efficiency of  $\text{NO}_x$  reduction increased with increase in the amount of the reburning fuel while in experiments efficiency reached maximum at about 10-15% reburning fuel heat input, and (3) modeling failed to predict the sharp decrease in the efficiency of  $\text{NO}_x$  reduction at large heat inputs of the reburning fuel.

Initial failure of the model to predict qualitatively the behavior of almond shells in reburning suggested that the model did not take into account some important aspects of the reburning process; particularly, failure to correctly represent the composition of gasification products, and specifically, the fuel-N and alkali metals in gasification products.

Because of the large volatile content of biomass fuels, it can be expected that most of the fuel-N from the waste fuel is released into the gas-phase. When injected in the reburning zone, N-containing species will be partially reduced to  $\text{N}_2$  and partially oxidized by excess air coming from the main combustion zone to form  $\text{NO}_x$  causing reduction in  $\text{NO}_x$  removal efficiency. It can be expected that the contribution of biomass fuel-N to  $\text{NO}_x$  formation increases with the increase in the amount of the reburning fuel. Presence of fuel-N in gasification products may be the reason why the efficiency of biomass reburning decreases for large heat inputs of the reburning fuel. Alkali-containing species, on the other hand, can increase efficiency of  $\text{NO}_x$  reduction in reburning and can be responsible for the high efficiency of  $\text{NO}_x$  reduction at small heat input of almond shells gasification products.

### *Impact of Nitrogen and Alkali Metals in Waste Fuels to NO<sub>x</sub> Reduction*

Figure 43 demonstrates that both fuel-N and sodium contents of biomass can affect the efficiency of NO<sub>x</sub> reduction in reburning. Specifically, the larger the product of fuel-N and sodium contents of biomass, the deeper the NO<sub>x</sub> reduction can be achieved. No correlation with biomass potassium content was found. It is possible that potassium is present in biomass mostly in the insoluble form, which is stable at reburning temperatures.

Since concentrations of N- and Na-containing species in gasification products were not measured, they had to be estimated. It was assumed that, as the waste fuel was gasified, 80% of the fuel-N was released (50% as NH<sub>3</sub> and 50% as N<sub>2</sub>). The remaining 20% fuel-N was assumed to be bound in the char residue. Concentrations of Na-containing species in reburning fuel were estimated using equilibrium calculations.

### *Prediction of NO<sub>x</sub> Reduction in Reburning*

Fuel nitrogen and sodium impacts on reburning performance were evaluated using modeling. Figure 44 (almond shells and non-recyclable waste paper), Figure 45 (LPG and wood “P”), and Figure 46 (municipal sewage sludge) present comparison between modeling predictions (lines) and experimental data (symbols) for reburning. Modeling predicted that performance of low-N fuels, such as LPG and non-recyclable waste paper, improved as the amount of reburning fuel increased. On the other hand, the efficiency of NO<sub>x</sub> reduction for almond shells, wood “P”, and municipal sewage sludge (fuels with high-N content) decreased when the amount of the reburning fuel reached 20%. This is because at 2,150°F NH<sub>3</sub> present in the reburning fuel was mostly oxidized to NO.

Modeling predicted that injection of almond shells gasification products into the reburning zone at an initial NO<sub>x</sub> (NO<sub>i</sub>) concentration of 100 ppm resulted in NO<sub>x</sub> production, and injection of non-recyclable waste paper gasification products resulted in only small NO<sub>x</sub> reduction. This is because contribution of fuel-N to NO<sub>x</sub> production becomes more significant at low NO<sub>i</sub>. Thus, the modeling results confirmed the experimental finding that biomass fuel-N and sodium content play an important role in NO<sub>x</sub> production/reduction in the reburning zone, and that gasified high-N content biomass fuels (particularly almond shells and municipal sewage sludge) do not work well as reburning fuels under classical reburning conditions (i.e., high reburning temperatures), especially when the initial boiler NO<sub>x</sub> levels are low. This discovery prompted a reburning optimization study, which is described in the next section.

The impact of Na in biomass fuels and  $\text{NH}_3$  in gasification products on reburning performance was also investigated. Modeling predicted that the presence of Na-containing species resulted in 3-5% improvement in  $\text{NO}_x$  reduction. It also predicted that the major contribution to the high efficiency of almond shells at small heat input of the reburning fuel came from the presence of  $\text{NH}_3$  in the gasification products. Predicted effects of Na and  $\text{NH}_3$  on  $\text{NO}_x$  reduction in almond shells reburning are demonstrated in Figure 47. The efficiency of  $\text{NO}_x$  reduction without Na and  $\text{NH}_3$  was smaller at 15% reburning heat input and larger at 20% reburning heat input. At 20% reburning heat input, the amount of  $\text{NH}_3$  in reburning fuel was too large, and some  $\text{NH}_3$  was oxidized to  $\text{NO}_x$ .

### *Optimization of Reburning*

The model was then used to optimize reburning with respect to initial temperature. First, the model was applied to fuels with low fuel-N content. Modeling predicted that performance of LPG and non-recyclable waste paper improved with increase in the flue gas temperature at which reburning fuel was injected. This prediction agrees with data on the effect of temperature on reburning for fuels with low fuel-N content. For these fuels, efficiency of  $\text{NO}_x$  reduction in reburning increases with an increase in temperature in the reburning zone. This is because at higher temperatures the reburning fuel is oxidized faster, resulting in faster generation of active species involved in  $\text{NO}_x$  reduction.

The model was then applied to biomass fuels with high fuel-N content. The line in Figure 48 shows the predicted efficiency of  $\text{NO}_x$  reduction in almond shells reburning as a function of flue gas temperature at which reburning fuel was injected at 10% reburning fuel heat input. Modeling predicted that the efficiency of  $\text{NO}_x$  reduction could be increased up to 70% by lowering the temperature in the reburning zone. This behavior is not typical for reburning and is due to  $\text{NO}_x$  reaction with  $\text{NH}_3$ . At high temperatures  $\text{NH}_3$  is mostly oxidized to  $\text{NO}_x$  and reduces the efficiency of  $\text{NO}_x$  reduction by the reburning fuel. At low temperatures,  $\text{NH}_3$  can reduce  $\text{NO}_x$ . The efficiency of  $\text{NO}_x$  reduction increased with a decrease in temperature because the optimum temperature for  $\text{NO}_x$  reduction by  $\text{NH}_3$  is about 1,800°F. Further, an optimum in  $\text{NO}_x$  reduction occurs even at lower temperatures in the presence of CO and  $\text{H}_2$ . Since concentrations of CO and  $\text{H}_2$  in gasification products of all tested biomass fuels were high, it should not come as a surprise that the predicted efficiency of  $\text{NO}_x$  reduction in almond shells reburning reached a maximum between 1,730°F and 1,800°F. Figure 48 shows that modeling predictions for the

temperature dependence of NO<sub>x</sub> reduction in reburning with almond shells gasification products were consistent with the experimental data trend.

Figure 49 summarizes the predicted impacts of the biogas N-content on NO<sub>x</sub> reduction performance of conventional (high-T) reburning and low-T reburning. As indicated above and shown in the figure, higher fuel-N content appears to decrease NO<sub>x</sub> reduction performance for reburning, whereas higher fuel-N appears to improve low-T reburning NO<sub>x</sub> reduction performance significantly. As fuel-N content increases from 0.3% to 1.9%, reburning NO<sub>x</sub> reduction performance drops from 66% to 52%, while low-T reburning NO<sub>x</sub> reduction improves from 38% to approximately 95% as fuel-N increases from 0.2% to 1.8%. These trends are to be expected since higher fuel-N available in the reburning case tends to convert to NO<sub>x</sub> at the higher temperatures of the conventional process. The higher fuel-N available in the low-T reburning case tends to reduce NO<sub>x</sub> according to the similar de-NO<sub>x</sub> reactions in the SNCR process.

Modeling results demonstrated that the efficiency of NO<sub>x</sub> control with gasification products of high-N fuels increased at lower temperatures and can be as high as approximately 70% at only 10% of reburning fuel by heat input. The optimum temperature for NO<sub>x</sub> control is defined by the composition of gasification products (CO, H<sub>2</sub>, hydrocarbons, N- and alkali-containing compounds), composition of the flue gas at the point of reburning fuel injection, and the temperature of flue gas at the point of reburning fuel injection.

### *Modeling of Advanced Reburning*

It is known that Advanced Reburning (AR) can provide higher efficiency of NO<sub>x</sub> reduction than basic reburning [5,6,7]. In AR, the N-agent and promoters are injected in different locations in the combustion system to achieve optimum NO<sub>x</sub> reduction. In AR-Rich, additives are injected into the fuel-rich environment of the reburning zone; while in AR-Lean, additives are injected into the fuel-lean environment of the burnout zone.

AR performance can be significantly impacted by the nitrogen content of the reburning fuel. Since AR performance relies on the de-NO<sub>x</sub> mechanisms that result from N-agent injection, if a reburning fuel already contains a high level of N, the injection of a N-agent does little to provide additional reduction on top of that already achieved with reburning. Two of the biomass fuels used in this study, municipal sewage sludge (MSS) and almond shells, have a relatively high nitrogen content. Therefore, AR performance may be enhanced if the reburning fuels (MSS and almond shells gasification products) have high levels of NH<sub>3</sub> as presented below.

### Modeling of AR-Rich

Modeling was first used to predict the effect of N-agent co-injection with gasification products of Almond Shells on  $\text{NO}_x$  reduction. For fuels with low fuel-N content, the N-agent co-injection can result in improvement of  $\text{NO}_x$  reduction. However, since concentration of  $\text{NH}_3$  in gasification products of Almond Shells is already significant (Dräger tube measurements indicated presence of about 800 ppm of  $\text{NH}_3$  at 7.3% reburning fuel heat input), it was not expected that co-injection of  $\text{NH}_3$  with reburning fuel would result in significant improvement in  $\text{NO}_x$  reduction. Only small change in the efficiency of  $\text{NO}_x$  reduction when  $\text{NH}_3$  is co-injected with the reburning fuel would serve as an additional confirmation that  $\text{NH}_3$  already present in gasification products plays an important role in  $\text{NO}_x$  reduction/production.

Figure 50 shows modeling predictions for the dependence of  $\text{NO}_x$  reduction on the amount of  $\text{NH}_3$  co-injected with the reburning fuel at 10% reburning fuel heat input. Experimental data are also shown. Modeling predicted (and supported by experiments) that  $\text{NH}_3$  co-injection had a small effect on  $\text{NO}_x$  reduction. The higher efficiency of  $\text{NO}_x$  reduction predicted by modeling than that observed in experiments is due to the fact that modeling over predicted efficiency of  $\text{NO}_x$  reduction for reburning without  $\text{NH}_3$  co-injection. This deviation, however, is only several percent larger than the uncertainty in experimental data ( $\pm 5\%$ ). Therefore, it is reasonable to conclude that the main process trends observed in the experiments are captured by the modeling approach.

Modeling was then applied to predict the effect of urea and sodium carbonate injection into the reburning zone on  $\text{NO}_x$  reduction. As in experiments, the reburning fuel in modeling was injected at 2,100°F, urea and sodium carbonate at 1,900°F, and overfire air at 1,680°F. The amount of the reburning fuel was 8 to 10% (depending on the fuel) relative to the total heat input.

As expected (Figure 51 for municipal sewage sludge and Figure 52 for almond shells), modeling predicted that injection of urea at  $\text{SR} = 1.5$  into the reburning zone had generally small effect on  $\text{NO}_x$  reduction. However, co-injection of 100 ppm of sodium carbonate with urea resulted in significant improvement of  $\text{NO}_x$  reduction.

### Modeling of AR-Lean

Modeling was applied to predict effect of urea and sodium carbonate injection into the burnout zone on  $\text{NO}_x$  reduction. The model was used to predict AR-Lean performance when

reburning with gasified municipal sewage sludge (MSS) products. These results are compared to experimental results in Figure 53. As indicated earlier, AR-Lean means that the urea and sodium carbonate are injected into the burnout zone. For these tests, the reburning fuel was injected at the lower, optimized temperature of 1840°F. The urea and sodium carbonate were co-injected with OFA at 1680°F. The amount of the reburning fuel was 7% relative to the total heat input.

The model and experimental results for MSS are in fairly good agreement. The model predicts that NO<sub>x</sub> reduction improves from 41% with 7% MSS reburning alone, to 83% when urea is added with an NSR of 1.5. The addition of 100 ppm of Na increases NO<sub>x</sub> reduction up to 93%. The fact that performance improved relatively little with the addition of Na suggests that gasified MSS contains an appropriate amount of alkali metals for good reburning performance. Overall, this data suggests that gasified MSS performs very well as a reburning fuel in an AR-Lean application.

To compare these results with another high-N reburning fuel, Figure 54 shows modeling predictions and experimental data for reburning with gasified almond shells. The model predicts that injection of urea at SR = 1.5 has a relatively small effect on NO<sub>x</sub> reduction, and this is confirmed by experiments. As in AR-Rich, this is due to the already high content of NH<sub>3</sub> in the reburning fuel. Co-injection of 100 ppm of sodium carbonate with urea, however, improved efficiency of NO<sub>x</sub> reduction to about 90%. These data suggest that the efficiency of basic reburning can be improved by optimizing the gasification process to produce gas with even higher content of alkali metals than that found in Almond Shells gasification products.

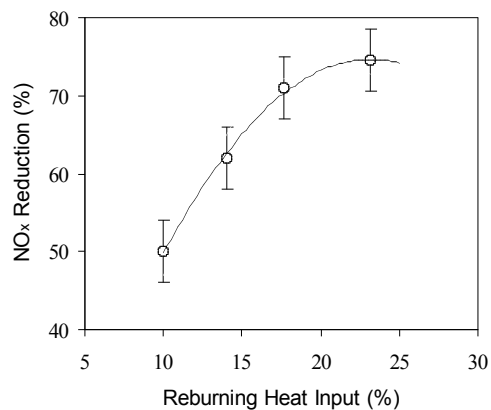


Figure 40. Modeling (lines) and experimental results for natural gas reburning ( $\text{NO}_i = 600$  ppm).

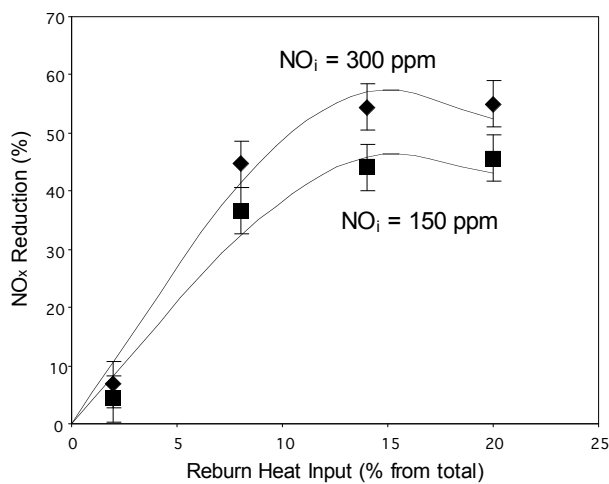


Figure 41. Experimental data (symbols) and modeling prediction (lines) for LPG reburning.

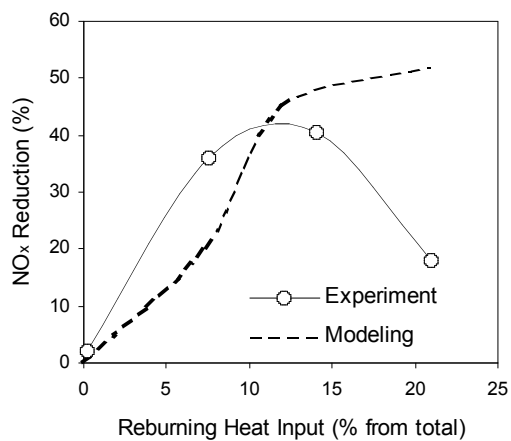


Figure 42. Comparison between modeling predictions and experimental data for reburning with Almond Shells gasification products.

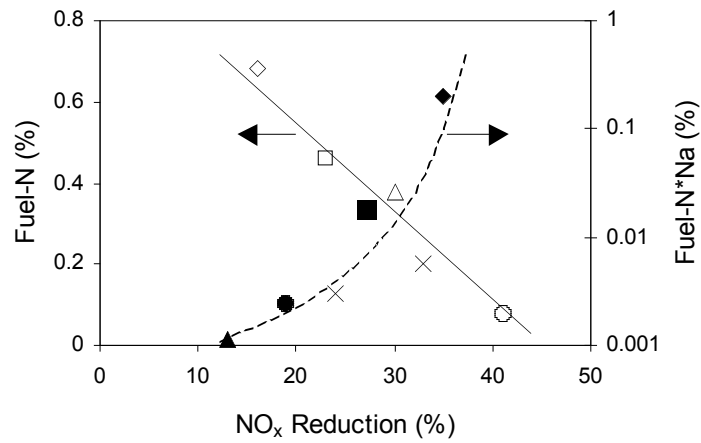


Figure 43. Correlations at  $\text{NO}_i = 300$  ppm between  $\text{NO}_x$  reduction and (1) biomass fuel-N content at 20% reburning fuel heat input (solid line and open symbols) and (2) between fuel-N and sodium content of biomass at 8% reburning fuel heat input (dashed line and filled symbols). Symbols represent: squares – Rice Straw, triangular – Wood P, circles – Waste Paper, crosses – Wood W, and rhombuses – Almond Shells.

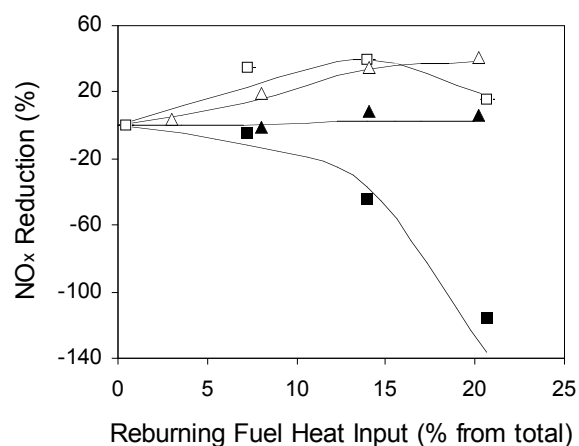


Figure 44. Comparison between modeling and experimental results. Squires – Almond Shells, triangles – Waste Paper. Open symbols – NO<sub>i</sub> = 300 ppm, filled symbols – NO<sub>i</sub> = 100 ppm.

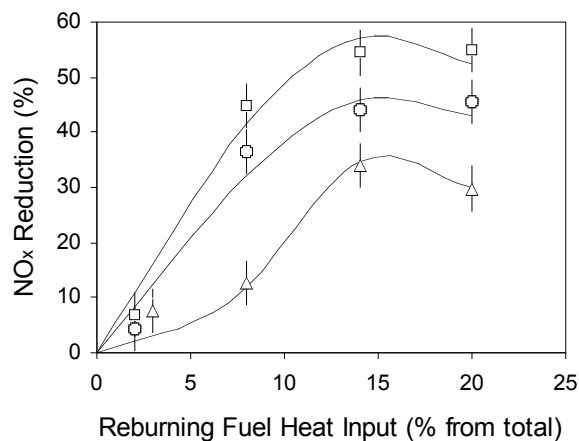


Figure 45. Comparison between modeling predictions and experimental data. Squires - LPG at NO<sub>i</sub> = 300 ppm, triangular – Wood P at NO<sub>i</sub> = 300 ppm, circles – LPG at NO<sub>i</sub> = 100 ppm.

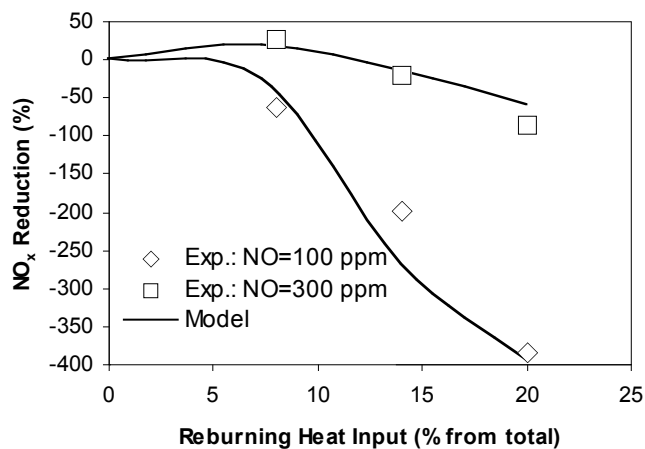


Figure 46. Experimental and modeling results for sewage sludge (reburn T = 2150°F).

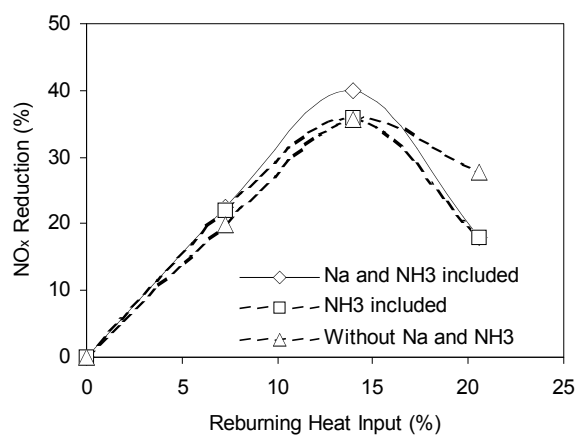


Figure 47. Predicted effects of Na and NH<sub>3</sub> on NO<sub>x</sub> reduction in Almond Shells reburning at 2150°F.

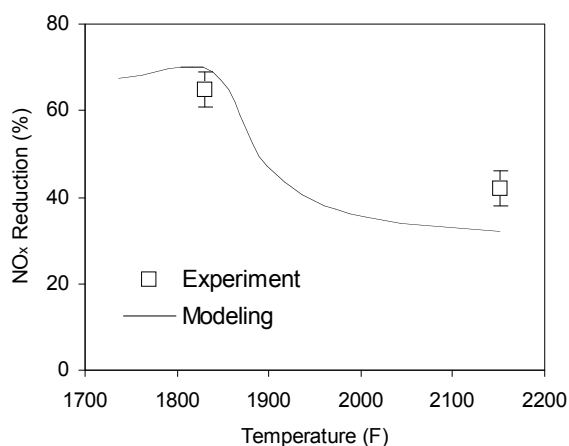


Figure 48. Predicted temperature dependence of the efficiency of NO<sub>x</sub> reduction in reburning with Almond Shells gasification products.

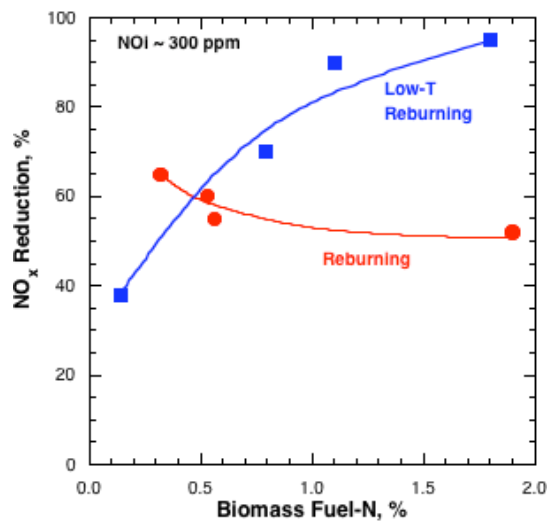


Figure 49. Impacts of fuel-N content on NO<sub>x</sub> reduction performance.

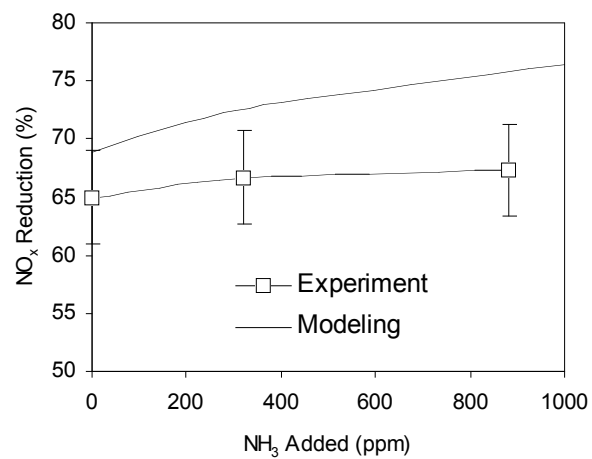


Figure 50. Effect of NH<sub>3</sub> co-injection with gasification products of Almond Shells on NO<sub>x</sub> reduction at 1840°F injection temperature.

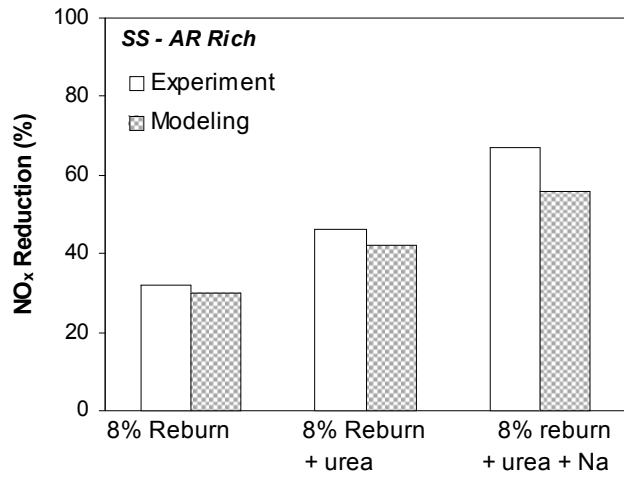


Figure 51. AR-Rich. Effect of urea and  $\text{Na}_2\text{CO}_3$  injection into the reburning zone on  $\text{NO}_x$  reduction at 8% gasified MSS reburning ( $T_{\text{RF}} = 2150^\circ\text{F}$ , Urea/Na at  $1900^\circ\text{F}$ ,  $T_{\text{OFA}} = 1680^\circ\text{F}$ ,  $\text{NO}_i = 280$  ppm,  $\text{N}_2$  atomizer,  $\text{NSR} = 1.5$ ,  $[\text{Na}] = 100$  ppm).

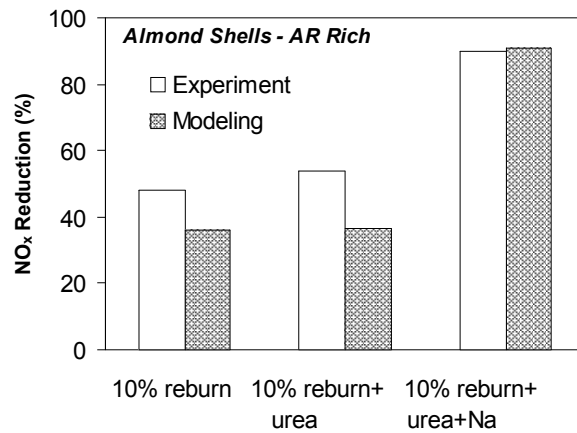


Figure 52. AR-Rich. Effect of urea and  $\text{Na}_2\text{CO}_3$  injection into reburning zone on  $\text{NO}_x$  reduction at 10% reburning heat input for almond shells.

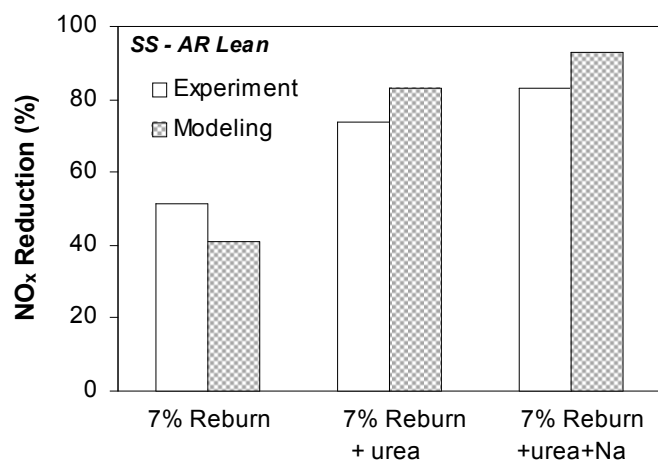


Figure 53. AR-Lean. Effect of urea and  $\text{Na}_2\text{CO}_3$  co-injection with OFA on  $\text{NO}_x$  reduction at 7% reburning ( $T_{\text{RF}}=1840^\circ\text{F}$ ,  $T_{\text{OFA}}=1680^\circ\text{F}$ ,  $\text{NSR}=1.5$ ,  $\text{Na}=100$  ppm,  $\text{N}_2$  atomizer, Urea & Na co-injected with OFA,  $\text{NO}_i = 280$  ppm).

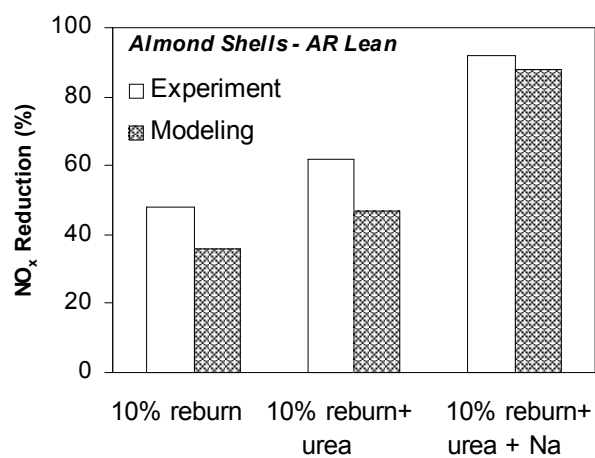


Figure 54. AR-Lean. Effect of urea and  $\text{Na}_2\text{CO}_3$  co-injection with OFA on  $\text{NO}_x$  reduction at 10% reburning heat input for almond shells.

### **3.7 Full Scale Conceptual Design**

Preliminary designs were developed for the integration of a Close-Coupled Gasification (CCG) system in the form of conventional reburning or low-temperature (low-T) reburning into the three California biomass boilers at Wheelabrator Shasta, Wadham Energy, and Woodland. The specific objectives of the design study were to:

- Develop a conceptual design for application of CCG to the three biomass-fired boilers.
- Evaluate impacts of CCG technology on boiler thermal performance and NO<sub>x</sub> emissions.

#### **3.7.1 CCG General System Components and Arrangement**

The CCG technology will consist of a fuel handling system, gasifier, gas delivery system, and gas injection system. The fuel handling system will serve to feed biomass to the gasifier. The gasifier will be used to gasify the biomass to produce a product syngas. The gas delivery system will then route the syngas from the gasifier to the gas injection system. The gas injection system will introduce the syngas into the boiler.

A number of commercial gasifier systems are available for use in the CCG process. The primary considerations in selection of the gasifier are whether to use an atmospheric or pressurized design, and whether to perform significant gas clean up prior to introducing the syngas to the boiler. For most applications, it is expected that the use of an atmospheric gasifier along with a minimal gas clean up system will represent the most economic system. Where the boiler design dictates the need for a cleaner syngas or where economics dictate the use of a higher quality syngas, a pressured gasifier system can be used.

#### **3.7.2 Boiler Descriptions**

The three plants cooperating in this project represent the major types of biomass boilers: Wheelabrator's Shasta is a stoker-fired boiler; Wadham Energy is a front-wall fired boiler; and Woodland Biomass is a circulating fluidized bed (CFB) boiler.

##### ***Wheelabrator Shasta***

Figure 55 shows a schematic side view of the Wheelabrator's Shasta boiler located in Anderson, California. The boiler is a spreader stoker manufactured by Zurn Industries, Inc. with a traveling grate. The boiler has a design steam generating capacity of 170 klb/hr of superheated steam at 905°F and 920 psig. The boiler fires wood chips as the main fuel while it uses natural

gas as the support fuel. Heated combustion air enters the grate as underfire air and through several levels air jets and overfire air ports located on the front and rear walls of the furnace. The boiler has a gas burner located on the rear wall. The boiler furnace is 18'-8" wide and 18'-0" deep.

A forced draft fan supplies the combustion air through an air heater where the air is heated to about 400°F. The flue gas exits the water-tube furnace and flows through a couple of superheater platens, a generating bank, an economizer and the airheater before being induced by an induced draft fan to the stack.

The boiler is designed to operate with an overall excess air level of 33% at full load. However, the unit is currently running with 47.5% excess air. The unit is currently equipped with an ammonia injection for NO<sub>x</sub> control. Two levels of ammonia injectors are located on the furnace front wall; with the lower elevation injectors are currently out of service. The current NO<sub>x</sub> emissions level is 0.15 lb/MMBtu with the ammonia injection in operation. It is projected that the baseline NO<sub>x</sub> emissions level would be 0.25 lb/MMBtu without the ammonia injection system.

### ***Wadham Energy***

Figure 56 shows general views of Wadham Energy suspension boiler located in Williams, California. The boiler is a front-wall fired boiler manufactured by Zurn Industries, Inc. The boiler fires rice hulls as the main fuel. The boiler furnace is 16'-8" wide and 16'-0" deep.

The boiler is equipped with eight circular located on the front wall on a 2 by 4 (column by row) array. The burners have a throat diameter of 26 inches. The fuel is transported to the fuel bins using a belt conveyor. The fuel flow rate to each burner is regulated using weight augers and the fuel is pneumatically transported to the burners using eight individual fuel injectors. Eight separate fuel-conveying fans supply the transport air to each injector. A forced draft fan supplies the combustion air through an air heater where the air is heated to about 450°F. The flue gas exits the water-tube furnace and flows through a superheater, a reheater, an economizer and a baghouse before being induced by an induced draft fan to the stack.

Based upon the nitrogen content in the fuel and the boiler design and operating characteristics, it is projected that the baseline NO<sub>x</sub> emission for the Wadham boiler would be approximately 0.30 lb/MMBtu.

## *Woodland*

Figure 57 shows a schematic side view of the Woodland Biomass boiler located in Woodland, California. The boiler is a circulating Fluidized bed boiler. The boiler fires a variety of biomass fuels with urban/agricultural biomass as the main fuels. The boiler furnace is 10'-0" wide and 10'-0" deep.

Heated combustion air enters a windbox located beneath the boiler bed and through air jets located on the front and rear walls of the furnace. The flue gas exits the water-tube furnace and flows through a cyclone where the bed material is recycled back to the furnace. The flue gas then flows through a series of superheaters and generating banks, and an economizer arranged vertically in the back pass of the boiler before being induced by an induced draft fan to the stack.

### **3.7.3 Conceptual Design**

In the development of the reburning system design, the most significant issue is to identify the appropriate locations for the reburning fuel and overfire air injectors. Boiler performance and operating data is then reviewed to establish a design basis for the reburning system. Finally, a preliminary design for the reburning system is developed from the design basis using empirical jet penetration and mixing models.

The biomass fuel compositions used in this conceptual design study are shown in Table 19. The Wheelabrator Shasta boiler normally fires wood chips with natural gas as support fuel. The Wadham Energy boiler fires predominantly Rice Hulls. The Woodland CFB burns a mixture of urban/agricultural biomass. The syngas will be produced and delivered to the boilers at a temperature of approximately 1,500°F. The syngas will have a higher heating value of 2,205 Btu/lb (164 Btu/scf).

### *Conventional Reburning*

The basis assumed for the design of the conventional reburning systems is summarized in Table 20 for the three boilers.

For the Wheelabrator boiler, the full load was assumed to be 170 klb/hr of steam flow rate, which corresponds to a calculated total heat input of 310 MMBtu/hr. The main fuel will be wood chips while the reburn fuel will be biomass syngas. The primary zone will be operated with about 10% excess air. The reburn system will be designed to supply 25% of total boiler heat input, which would bring the reburn zone stoichiometric ratio to about 0.9. The burnout zone will

be operated at the boiler normal excess air level of 47.5%, which requires the OFA system to supply approximately 39.2% of combustion air.

For the Wadham Energy, the boiler total heat input will be 340 MMBtu/hr. The main fuel will be rice hulls, while the reburning fuel will be syngas. The primary, reburning and burnout zone stoichiometric ratios will be 1.10, 0.87, and 1.45, respectively. The reburning fuel capacity will be 25% of total heat input while the OFA capacity will be 40.3% of total combustion air.

For Woodland boiler, it is not feasible to apply conventional reburning due to low boiler gas temperatures. (~1,500°F).

### ***Low Temperature Reburning***

The basis assumed for the design of the low-T reburning systems is summarized in Table 21 for the three boilers.

For the Wheelabrator boiler, the full load was assumed to be 170 klb/hr of steam flow rate, which corresponds to a calculated total heat input of 310 MMBtu/hr. The main fuel will be wood chips while the reburning fuel will be syngas. The primary zone will be operated with 47.5% excess air. The reburning system will be designed to supply 12.5% of total boiler heat input, which would bring the burnout zone stoichiometric ratio to about 1.34. There is no OFA injection system.

For the Wadham Energy, the boiler total heat input will be 340 MMBtu/hr. The primary and burnout zone stoichiometric ratios will be 1.45 and 1.3, respectively. The reburn fuel capacity will be 12.5% of total heat input.

For Woodland boiler, the boiler total heat input will be 155 MMBtu/hr. The primary and burnout zone stoichiometric ratios will be 1.35 and 1.2, respectively.

## **3.7.4 CCG Design Integration With Boilers**

### ***Wheelabrator Shasta***

#### **Conventional Reburning**

The approach developed for application of biomass syngas reburning to the Wheelabrator Shasta is illustrated in Figure 58. The proposed reburning fuel injection elevation for this unit is at the existing secondary OFA elevation of 522'-0", which is slightly above the bullnose elevation of 519'-2". The gas burner on the rear wall will be taken out of service during reburning. The proposed reburning fuel elevation is approximately 20 feet above the grate and

should provide sufficient separation between the main flames and the reburning fuel injection point. Sufficient residence time in the reburning zone is needed to ensure complete mixing and reaction. The proposed OFA injection elevation is at Elevation 535'-0". This approach will provide more than 900 milliseconds of residence time for the reburning zone.

The conventional reburning system design was based on the boiler full load of 170 klb/hr of steam flow using the design basis shown in Table 20. The  $\text{NO}_x$  reduction performance achieved with reburning is sensitive to both the reburning zone stoichiometric ratio and the initial  $\text{NO}_x$  level. Both of these parameters are influenced by the stoichiometric ratio in the burners. In addition, in staged combustion systems, such as that installed on Shasta, reburning performance can be reduced when the reburning fuel is injected under conditions that are already fuel rich. Therefore, achieving the lowest emissions requires careful balancing between the grate and reburning zone stoichiometric ratios. At Shasta, since the syngas flow rate will be essentially constant at full load, the grate zone stoichiometric ratio is the primary parameter that can be adjusted to maximize  $\text{NO}_x$  emissions reduction while minimizing the impacts of the reburning system on boiler performance. It was assumed that the grate could be operated at a stoichiometric ratio of approximately 1.1 at full load. For the maximum syngas flow rate of 25% of total heat input, this corresponds to a reburning zone stoichiometric ratio 0.9. At this condition, sufficient overfire air would be injected to bring the boiler back to its normal operating excess air level of 47.5%. A process flow diagram and a material balance for application of biogas reburning to Shasta is shown in Figure 59.

#### Low Temperature Reburning

The approach developed for application of low-T reburning to the Wheelabrator Shasta boiler is also illustrated in Figure 58. The syngas injectors will be placed on the furnace front wall at the nose elevation, where the furnace gas temperatures are believed to be suitable for low-T reburning application ( $\sim 1,700^\circ\text{F}$ ). The low-T reburning system design was also based on the boiler full load of 170 klb/hr of steam flow using the design basis shown in Table 21. It is assumed that the grate would be operated at its normal excess air level of 47.5%. With the injection of the maximum biogas flow rate of 12.5% of total heat input, the burnout zone stoichiometric ratio would be 1.34. A process flow diagram and a material balance for application of low-T reburning to Shasta is shown in Figure 60.

## *Wadham Energy*

### Conventional Reburning

The approach developed for application of conventional syngas reburning to the Wadham Energy boiler is illustrated in Figure 61. The proposed reburning fuel injection elevation for this unit is at the top burner elevation of 134'-2". The top row burners will be taken out of service during reburning. The proposed reburning fuel elevation is approximately 8 feet above the second row burner elevation and is estimated to provide more than 550 milliseconds between the main flames and the reburning fuel injection point. The proposed OFA injection elevation is at Elevation 146'-2". This approach will provide more than 750 milliseconds of residence time for the reburning zone.

The reburning system design was based on the boiler full load using the design basis shown in Table 20. It was assumed that the burners could be operated at a stoichiometric ratio of approximately 1.1 at full load. For the maximum syngas flow rate of 25% of total heat input, this corresponds to a reburning zone stoichiometric ratio 0.87. At this condition, sufficient overfire air would be injected to bring the boiler back up to its normal operating excess air level of 45%. A process flow diagram and a material balance for application of conventional reburning to Wadham is shown in Figure 62.

### Low Temperature Reburning

The approach developed for application of low-T reburning to the Wadham Energy boiler is illustrated in Figure 61. The syngas injectors will be placed at a vertical cross-section immediately upstream of the secondary superheater platens. The low-T reburning system design was also based on the boiler full load using the design basis shown in Table 21. It was assumed that the grate would be operated at its normal excess air level of 45%. With the injection of the maximum syngas flow rate of 12.5% of total heat input, the burnout zone stoichiometric ratio would be 1.3. A process flow diagram and a material balance for application of low-T reburning to Wadham is shown in Figure 63.

## *Woodland*

### Low Temperature Reburning

The approach developed for application of low-T reburning to the Woodland boiler is illustrated in Figure 64. The syngas injectors will be placed at a distance above the bed in the freeboard section where the furnace gas temperatures are in the range of 1,700°F. The low-T reburning system design was also based on the boiler full load using the design basis shown in Table 21. It was assumed that the grate would be operated at its normal excess air level of 35%. With the injection of the maximum biogas flow rate of 12.5% of total heat input, the burnout zone stoichiometric ratio would be 1.2. A process flow diagram and a material balance for application of low-T reburning to Woodland is shown in Figure 65.

### **3.7.5 Injector Specifications**

The reburning process material balances, the selected injection elevations, and the boilers geometry were used to develop specifications for the reburning fuel and overfire air systems, based upon an evaluation of the requirements for obtaining effective mixing of the injected stream with the boiler flue gas. The specifications were developed using jet mixing models and experience to identify the number of nozzles, and injection velocities necessary to provide rapid and uniform mixing of the injected stream across the boiler cross section.

### *Conventional Reburning*

The preliminary injector specifications for the reburning fuel and overfire air injection systems for applying conventional reburning to the three boilers are shown in Table 22.

For Wheelabrator Shasta, the reburning fuel injectors will be placed on both the front and rear walls of the furnace at Elevation 522'. There will be eight port openings; four on each wall. Each port opening has one injector for a total of eight injectors. The injector has an inside diameter of 10 inches. At the design conditions, a velocity head of 0.8 "wg would be needed for achieving good jet penetration. The overfire air ports will be placed on the furnace front wall at Elevation 535'. There will be a total of four ports, which are a double concentric design. The inner nozzle has an inside diameter of 12 inches, while the annular port has an inside diameter of 19.4 inches. The ports require 1.05 "wg of velocity head for achieving good mixing at the design conditions.

For Wadham Energy, the reburning fuel injectors will be placed on both the front wall of the furnace at Elevation 134'-2". There will be four port openings. Each port opening has one injector for a total of eight injectors. The injector has an inside diameter of 12.5 inches. At the design conditions, a velocity head of 1.6 "wg would be needed for achieving good jet penetration. The overfire air ports will be placed on the furnace front wall at Elevation 146'-2". There will be a total of four ports, which are a double concentric design. The inner nozzle has an inside diameter of 12 inches, while the annular port has an inside diameter of 19.7 inches. The ports require 0.96 "wg for achieving good mixing at the design conditions.

### *Low-T Reburning*

The preliminary injector specifications for the reburning fuel systems for applying low-T reburning to the three boilers are shown in Table 23.

For Wheelabrator Shasta, the reburning fuel injectors will be placed on the front wall at the nose elevation. There will be six port openings. Each port opening has one injector for a total of six injectors. The injector has an inside diameter of 5 inches. At the design conditions, a velocity head of 5.7 "wg would be needed for achieving good jet penetration.

For Wadham Energy, the reburning fuel injectors will be placed at a cross-section at the entrance of the secondary superheater on both side walls. There will be eight port openings; four on each side wall. Each port opening has one injector for a total of eight injectors. The injector has an inside diameter of 5 inches. At the design conditions, a velocity head of 3.9 "wg would be needed for achieving good jet penetration.

For Woodland, the reburning fuel injectors will be placed at a cross-section at a distance above the bed. There will be six port openings; two on the front wall and two on each of the two side walls. Each port opening has one injector for a total of six injectors. The injector has an inside diameter of 5 inches. At the design conditions, a velocity head of 1.4 "wg would be needed for achieving good jet penetration.

### **3.7.6 Thermal Performance Analysis**

Heat transfer modeling was conducted to evaluate impacts of reburning and low-T reburning operations on the boiler thermal performance as compared to baseline operation. Specifically, the studies use heat transfer modeling tools to evaluate changes in the (1) furnace

gas temperature profiles, (2) waterwall/exchanger heat absorption and fouling profiles, (3) boiler heat loss efficiency, and (4) carbon in ash, relative to baseline.

### ***Heat Transfer Modeling Procedure***

A two-dimensional furnace combustion and heat transfer code is used to evaluate the thermal characteristics of the boiler furnace. The furnace heat transfer code divides the furnace geometry into a series of zones, which are used in the heat transfer analysis. The furnace heat transfer code calculates radiative heat exchange between upper furnace radiant heat exchangers and the lower furnace high temperature zones, and handles complicated boundary conditions such as variation of waterwall/exchanger fouling patterns and emissivities. To permit a rigorous solution for the radiative heat transfer, the radiation calculation is decoupled from a solution of the momentum conservation equation. Therefore, the flow field is a required input to the code. The flow field can be generated from several sources: a computational fluid dynamics code, physical modeling, or based on analogy with boilers that have a similar geometry and flow field.

A key element of this code is the radiation submodel for calculating radiative heat exchange in the boiler based upon division of the furnace into a set of volume and surface zones. This submodel is based on a semi-stochastic method derived from pure Monte-Carlo techniques, and considers radiative species such as CO<sub>2</sub>, H<sub>2</sub>O, and soot as non-gray radiative species, while ash and char are considered as gray radiative species.

### ***Impacts of Conventional Reburning***

Impacts of biomass syngas reburning on a tangentially fired boiler are shown in Table 24, which compares the predicted reburning parameters at full load with those of baseline operation. An increase in total heat absorption during reburning results in a slightly higher steam generation rate and the steam temperature increases by 35 degrees. Reburning is also predicted to result in a reduction in total heat release and a loss of heat absorption in the backpass. The heat released and sensible heat reduction in the burner region is sufficient to produce adequate waterwall heat absorption. The heat loss efficiency is approximately 1.5% less during reburning. Carbon in ash increases slightly, by less than 1%.

Figure 66 shows the predicted temperature profiles for the baseline and reburning cases. The stoichiometric burner distribution is notably lower in the burner region than that for baseline burner conditions. Injection of air at the OFA port lowers the gas temperature, which then

increases above baseline temperatures beyond that point resulting in a lower furnace exit gas temperature.

### *Impacts of Low-T Reburning*

The impacts of low-T reburning on the same tangentially fired boiler are shown in Table 25. A slight increase in total heat absorption during low-T reburning results a steam temperature increase of 47°F. The heat loss efficiency is approximately 0.5% less during low-T reburning. Carbon in ash decreases slightly, by more than 1%.

Figure 67 shows the predicted temperature profiles for the baseline and low –T reburning cases. The stoichiometric burner distribution is notably lower in the burner region than that for baseline burner conditions. Injection of air at the OFA ports lowers the upper furnace gas temperatures beyond the baseline levels. Injection of the biomass syngas upstream of the secondary SH tubes results in a slight increase in flue gas temperature.

### **3.7.7 NO<sub>x</sub> Projections**

Process models based upon detailed chemical kinetics and full-scale reburning experience were used to predict the impacts of the biomass reburning and low-T reburning systems on NO<sub>x</sub> emissions from Wheelabrator Shasta, Wadham Energy and Woodland boilers. The NO<sub>x</sub> projections attempt to take into account all of the various parameters (temperature, residence time, stoichiometry, initial NO<sub>x</sub> level, reburning fuel mixing, reburning fuel characteristics, etc.) that are believed to have the most significant influence on the performance of the reburning process.

Note that the impacts of biomass reburning and low-T reburning on boiler emissions and performance will be site specific. The NO<sub>x</sub> reduction performance that can be achieved in a particular application depends upon the boiler design and operating characteristics, the reburning system design, and the characteristics of the syngas supplied from the gasifier. The syngas characteristics, in turn, depend upon the properties of the biomass fuels that are being gasified.

The NO<sub>x</sub> reduction performance achievable with reburning is sensitive to both the reburning zone stoichiometric ratio and the initial NO<sub>x</sub> level. Both of these parameters are influenced by the stoichiometric ratio in the burners. In addition, in staged combustion systems, reburning performance can be reduced when the reburning fuel is injected under conditions that

are already fuel rich. Therefore, achieving the lowest emissions requires careful balancing between the burner and reburning zone stoichiometric ratios.

The NO<sub>x</sub> reduction performance achievable with low-T reburning is extremely sensitive to the thermal environment and chemical composition (i.e, initial NO<sub>x</sub>, CO) of the flue gas at the injection location, syngas fuel composition, and injector mixing performance. Although small-scale test and modeling results have indicated that up to 70% NO<sub>x</sub> reduction could be achievable with low-T reburning, the actual NO<sub>x</sub> reduction achievable in full-scale systems would be expected to be substantially less. This is due to the non-uniformity of the flue gas temperatures and compositions, which are usually expected in the full-scale systems. In addition, the initial NO<sub>x</sub> levels are typically much lower in biomass combustions such as the three subject boilers (as compared to coal, oil or gas-fired combustion systems), and especially in a CFB boiler such as Woodland. The actual NO<sub>x</sub> reduction levels would be expected to be even lower.

Given the above considerations, projections were developed for the NO<sub>x</sub> emission levels achievable on the three subject boilers with biomass reburning at full load, and the results are presented in Table 26:

- For Wheelabrator, biomass reburning is expected to achieve 40 to 65% NO<sub>x</sub> reductions from the baseline NO<sub>x</sub> level of 0.25 lb/MMBtu. The expected final NO<sub>x</sub> emissions are 0.09 – 0.15 lb/MMBtu. Low-T reburning is expected to achieve 20 – 50% NO<sub>x</sub> reduction. The expected final NO<sub>x</sub> emissions are 0.12 – 0.20 lb/MMBtu.
- For Wadham, biomass reburning is expected to achieve 40 to 65% NO<sub>x</sub> reductions from the projected baseline NO<sub>x</sub> level of 0.30 lb/MMBtu. The expected final NO<sub>x</sub> emissions are 0.10 – 0.18 lb/MMBtu. Low-T reburning is expected to achieve 20 – 50% NO<sub>x</sub> reduction. The expected final NO<sub>x</sub> emissions are 0.15 – 0.24 lb/MMBtu.
- For Woodland, low-T reburning is expected to achieve somewhat low NO<sub>x</sub> reductions, in the range 20 – 30% due to the extremely low initial NO<sub>x</sub> level of 0.08 lb/MMBtu. The expected final NO<sub>x</sub> emissions are 0.056 – 0.064 lb/MMBtu.

Note the above projections provide a range of NO<sub>x</sub> reductions because of several uncertainties of the boiler operation and performance database along with the design assumptions that were used in this design study. The upper bounds, i.e., 65 or 50% NO<sub>x</sub> reductions, represent the optimistic levels achievable with the optimum injection location, furnace temperature profiles, and injector mixing performance. The lower bounds, i.e., 40 or 20% NO<sub>x</sub> reductions, represent the worst case

scenarios where the injection location would not be optimum, high furnace temperature quench rates, and optimum injector mixing performance is difficult to achieve.

### **3.7.8 Summary and Conclusions**

The primary objective of this study was to develop a preliminary design for integration of the CCG technology in the form of conventional reburning or low-T reburning into three California biomass boilers. The CCG system will be used to reduce NO<sub>x</sub> emissions and will permit the use of renewable fuels at the plant. In this study, GE applied a design methodology that uses analytical tools to develop preliminary injector design specifications. In addition, process models were applied to each boiler to predict impacts of reburning on NO<sub>x</sub> emissions.

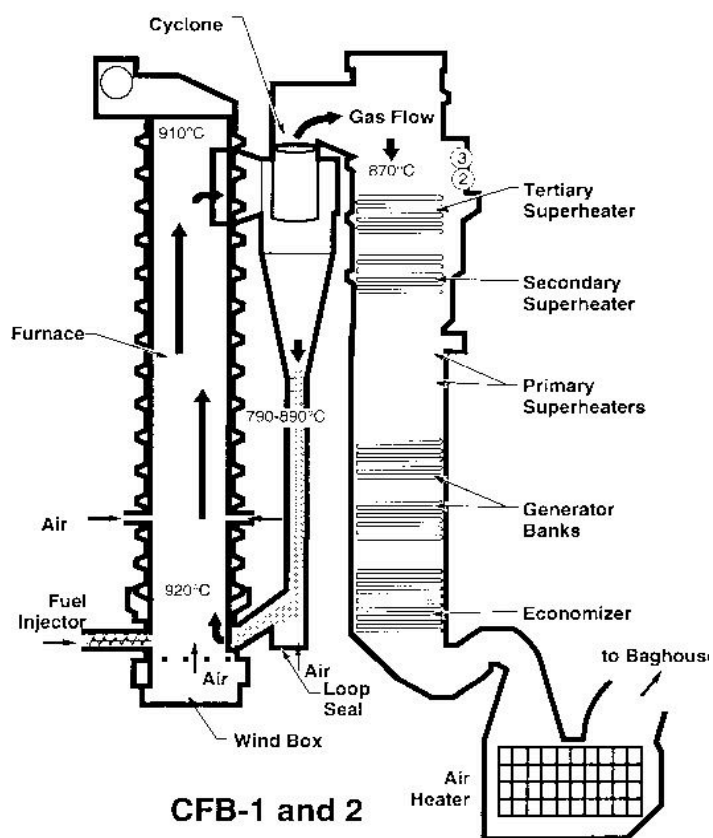
The CCG technology will consist of a system for routing biogas from the gasifier to the boiler and injecting it above the main burner zones and a system for injecting overfire air into the furnace. The injector parameters presented in Section 3.7.5 for each boiler are preliminary, and a more detailed design approach by the use of a physical flow model would be necessary to derive the final injector specifications.

Based upon a detailed heat transfer study of a biomass reburning application on a tangentially coal-fired boiler, it was determined that the reburning operation does not have a significant effect on the gas temperature distribution, steam flow rate and temperature, and overall thermal performance. Reburning was found to have a minor impact on boiler heat loss efficiency, primarily due to changes in dry gas combustible and combustion of fuel hydrogen. Steam temperatures and flow rates and percent carbon in ash remained generally unchanged while no significant changes in heat loss efficiencies were observed.

The ability of a plant to realize the benefits of CCG on NO<sub>x</sub> control will depend on the type of boiler, the existing NO<sub>x</sub> permit and the availability of alternative fuels at reduced costs. It appears from this analysis that CCG technologies in the form of biomass reburning and low-T reburning can effectively be applied to the three subject boilers. Pilot-scale data and modeling predictions (Sections 3.4 and 3.6) have demonstrated that 10-25% producer gas can reduce NO<sub>x</sub> emissions by up to 65% in basic reburning and up to 90% in advanced reburning; any quality of gas is acceptable, especially that with hydrocarbons, CO, H<sub>2</sub>, and ammonia. This study has made some certain estimates and/or assumptions on the boilers' baseline NO<sub>x</sub> emissions. Therefore, these baseline NO<sub>x</sub> levels need to be validated when the CCG technology is considered in future phases of this project.

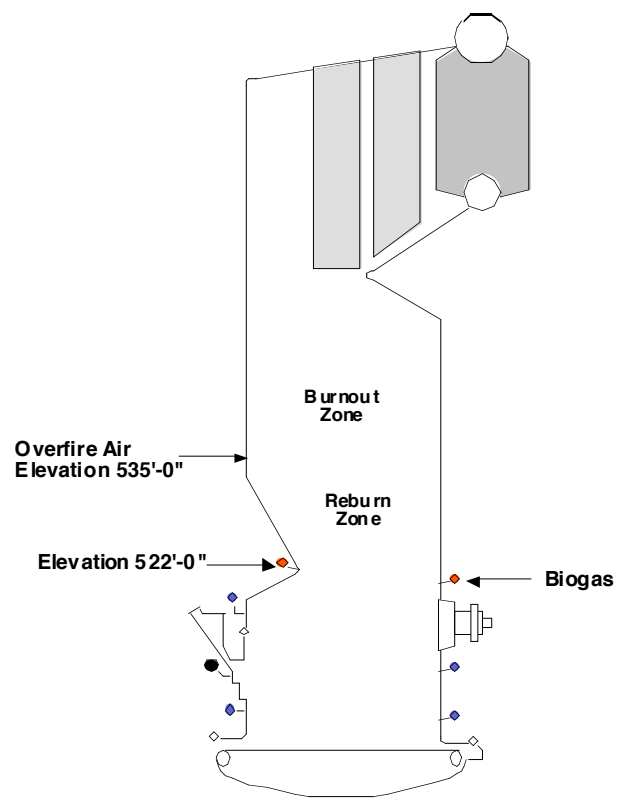




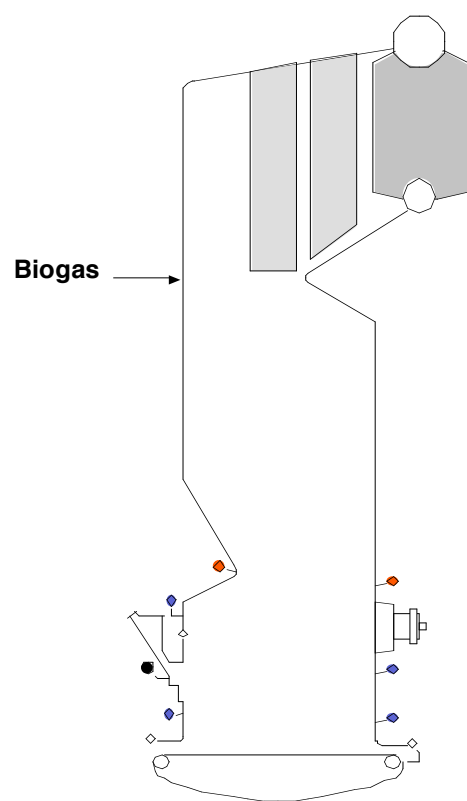


Source: Miles, et.al., Cal. Alkali Deposits in Biomass Power Plants, 1995.

Figure 57. Circulating Fluidized Bed at Woodland Biomass.

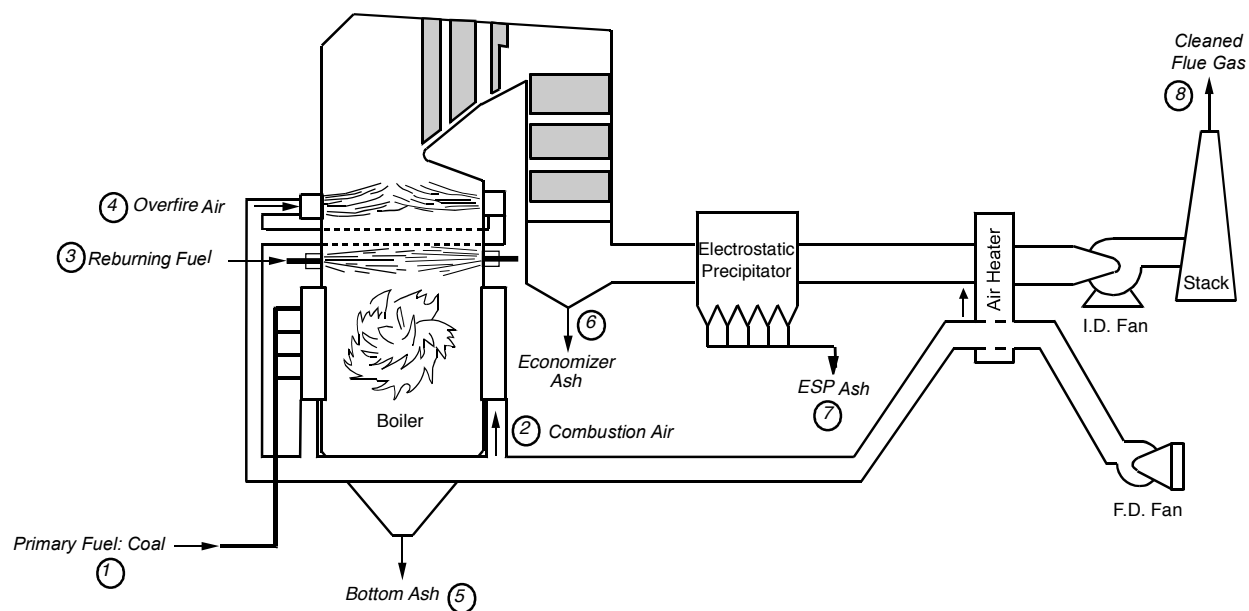


a) Conventional reburning



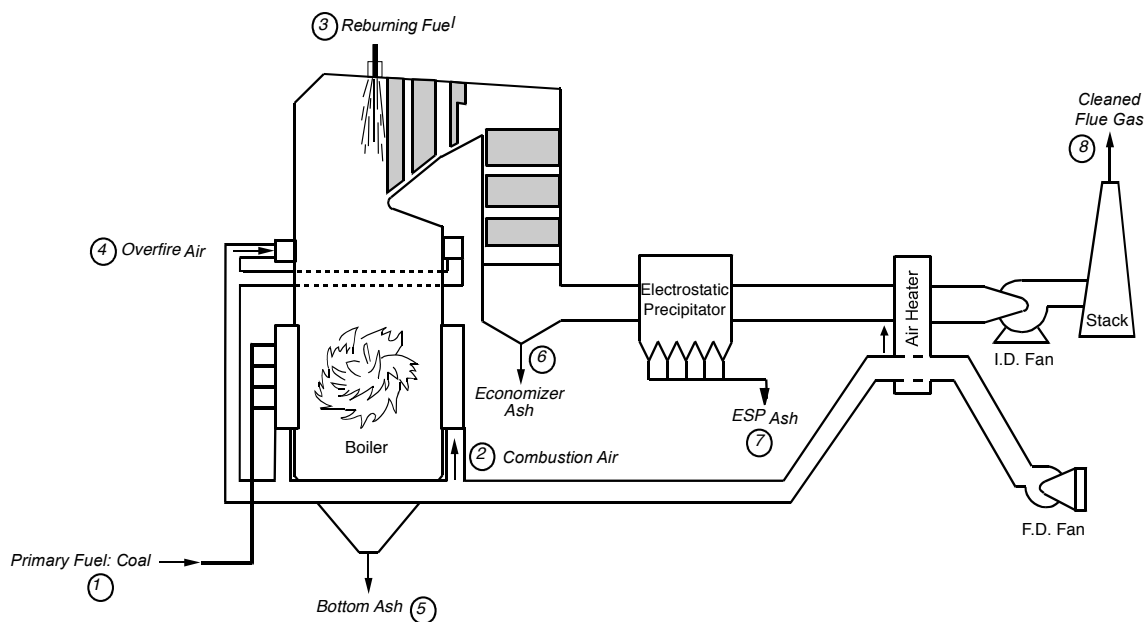
b) Low-T reburning

Figure 58. Application of reburning technologies to Wheelabrator Shasta boiler.



STREAM NUMBER	1	2	3	4	5	6	7	8
DESCRIPTION	Primary Fuel: Wood Chips	Coal Combustion Air	Reburning Fuel: Biogas	Overfire Air	Boiler Bottom Ash	Economizer Hopper Ash	ESP Ash	Flue Gas to Stack
GAS SIDE:								
Air (lbs/hr), dry		183,298		118,197				
Air (SCFM), dry		39,882		25,717				
Flue Gas (lbs/hr)								389,092
Flue Gas (SCFM)								82,352
SOLID SIDE:								
Primary Fuel (lbs/hr)	54,069		35,150					
Fuel Inerts (lbs/hr)	1,622		7,864		1,541	81		
Total Waste Solids (lbs/hr)	1,622				1,541	81		

Figure 59. Process flow diagram applying conventional reburning to Wheelabrator Shasta boiler.



STREAM NUMBER	1	2	3	4	5	6	7	8
DESCRIPTION	Primary Fuel: Wood Chips	Coal Combustion Air	Reburning Fuel: Biogas	Overfire Air	Boiler Bottom Ash	Economizer Hopper Ash	ESP Ash	Flue Gas to Stack
GAS SIDE:								
Air (lbs/hr), dry		286,751						
Air (SCFM), dry		62,391						
Flue Gas (lbs/hr)								365,515
Flue Gas (SCFM)								78,008
SOLID SIDE:								
Primary Fuel (lbs/hr)	63,081		17,575					
Fuel Inerts (lbs/hr)	1,892		3,932		473	95		
Total Waste Solids (lbs/hr)	1,892				473	95		

Figure 60. Process flow diagram applying low-T reburning to Wheelabrator Shasta boiler.

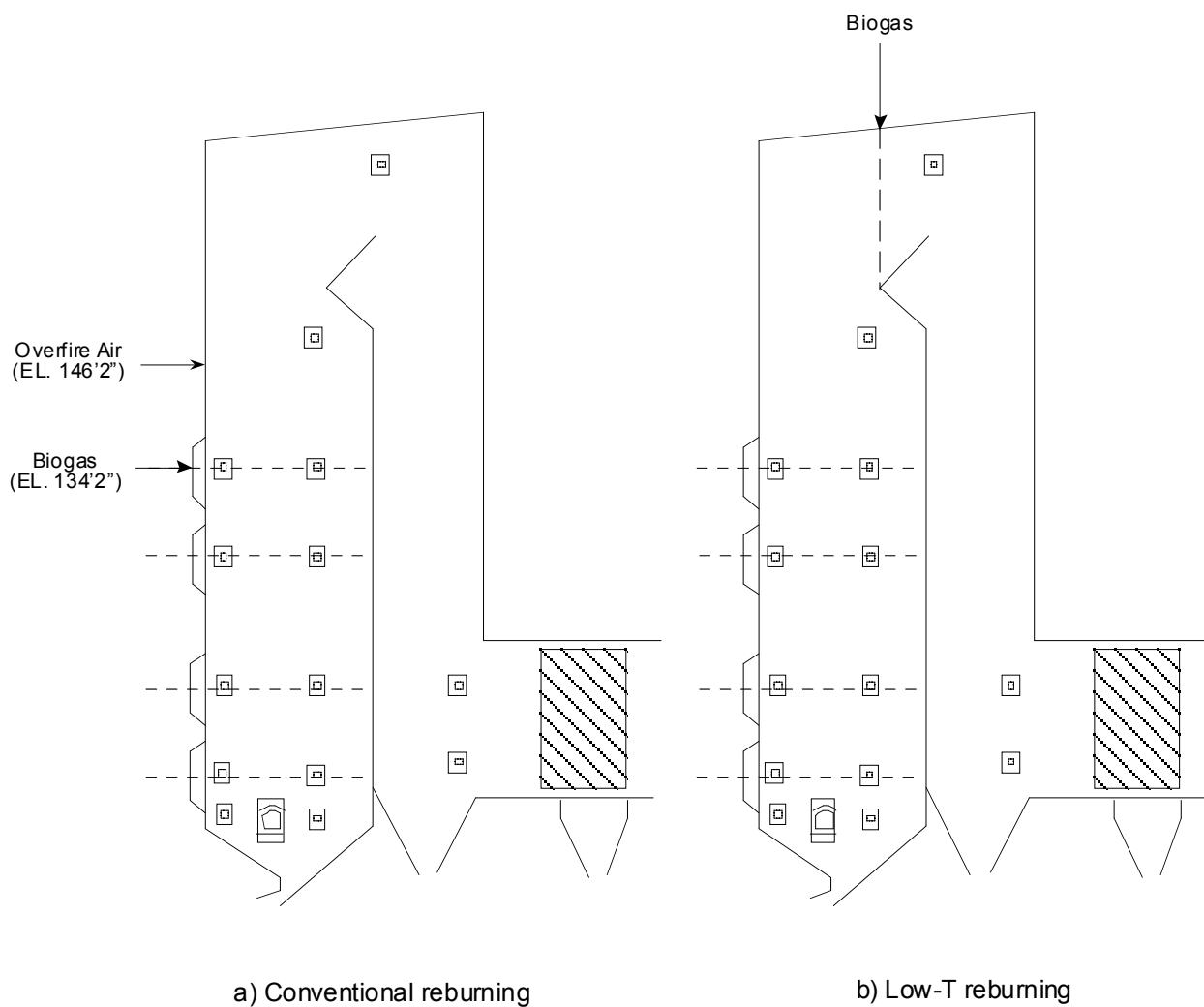
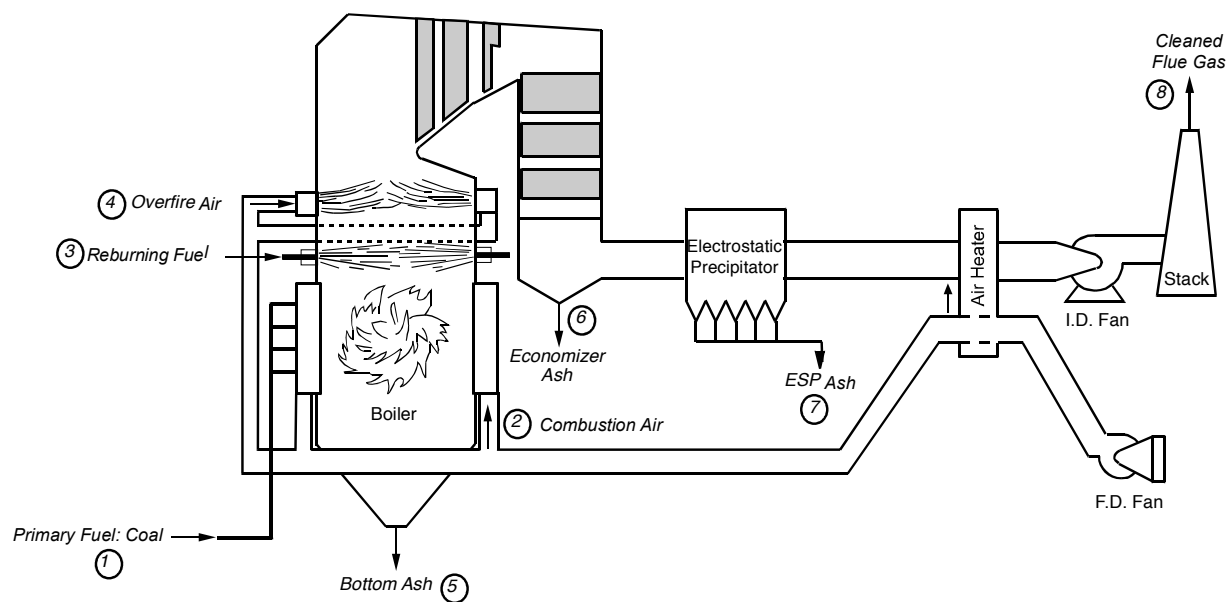
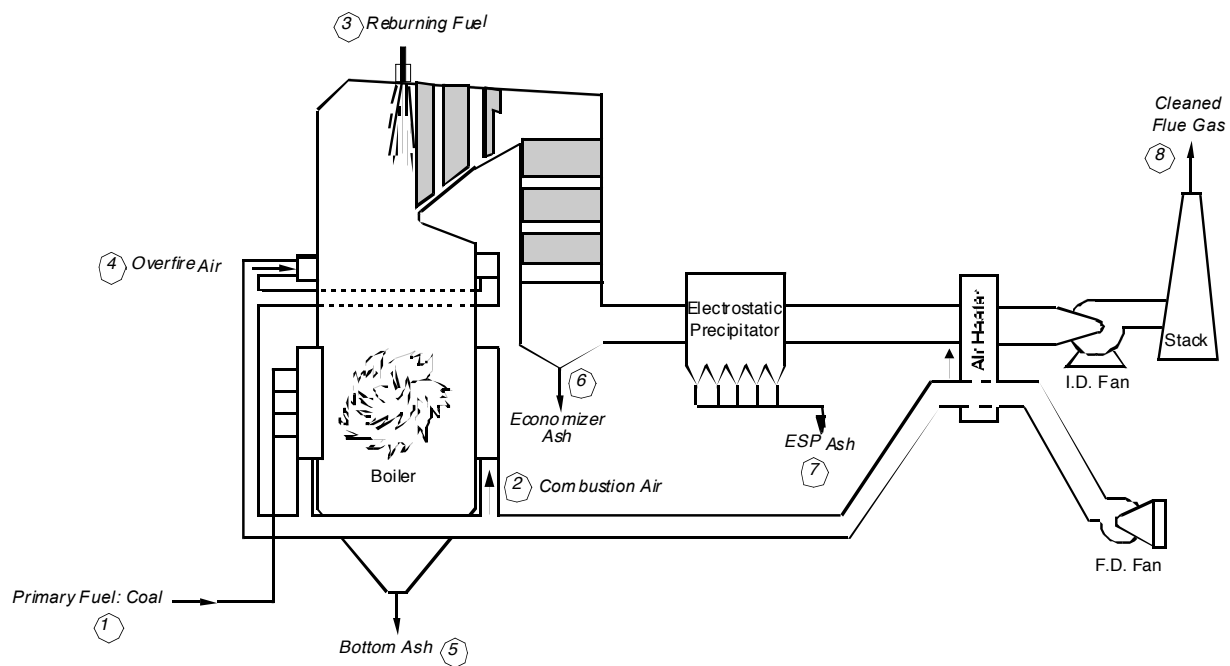


Figure 61. Application of reburning to the Wadham Energy boiler.



STREAM NUMBER	1	2	3	4	5	6	7	8
DESCRIPTION	Primary Fuel: Rice Hulls	Coal Combustion Air	Reburning Fuel: Biogas	Overfire Air	Boiler Bottom Ash	Economizer Hopper Ash	ESP Ash	Flue Gas to Stack
GAS SIDE:								
Air (lbs/hr), dry		167,894		113,388				
Air (SCFM), dry		36,530		24,671				
Flue Gas (lbs/hr)								350,657
Flue Gas (SCFM)								71,895
SOLID SIDE:								
Primary Fuel (lbs/hr)	37,500		38,551					
Fuel Inerts (lbs/hr)	6,675		8,624		3,204	1,335		
Total Waste Solids (lbs/hr)	6,675				3,204	1,335		

Figure 62. Process flow diagram applying conventional reburning to Wadham Energy boiler.



STREAM NUMBER	1	2	3	4	5	6	7	8
DESCRIPTION	Primary Fuel: Rice Hulls	Coal Combustion Air	Reburning Fuel: Biogas	Overfire Air	Boiler Bottom Ash	Economizer Hopper Ash	ESP Ash	Flue Gas to Stack
GAS SIDE:								
Air (lbs/hr), dry		258,008						
Air (SCFM), dry		56,138						
Flue Gas (lbs/hr)								313,269
Flue Gas (SCFM)								64,298
SOLID SIDE:								
Primary Fuel (lbs/hr)	43,740		19,307					
Fuel Inerts (lbs/hr)	7,786		4,319		3,737	1,557		
Total Waste Solids (lbs/hr)	7,786				3,737	1,557		

Figure 63. Process flow diagram applying low-T reburning to Wadham Energy boiler.

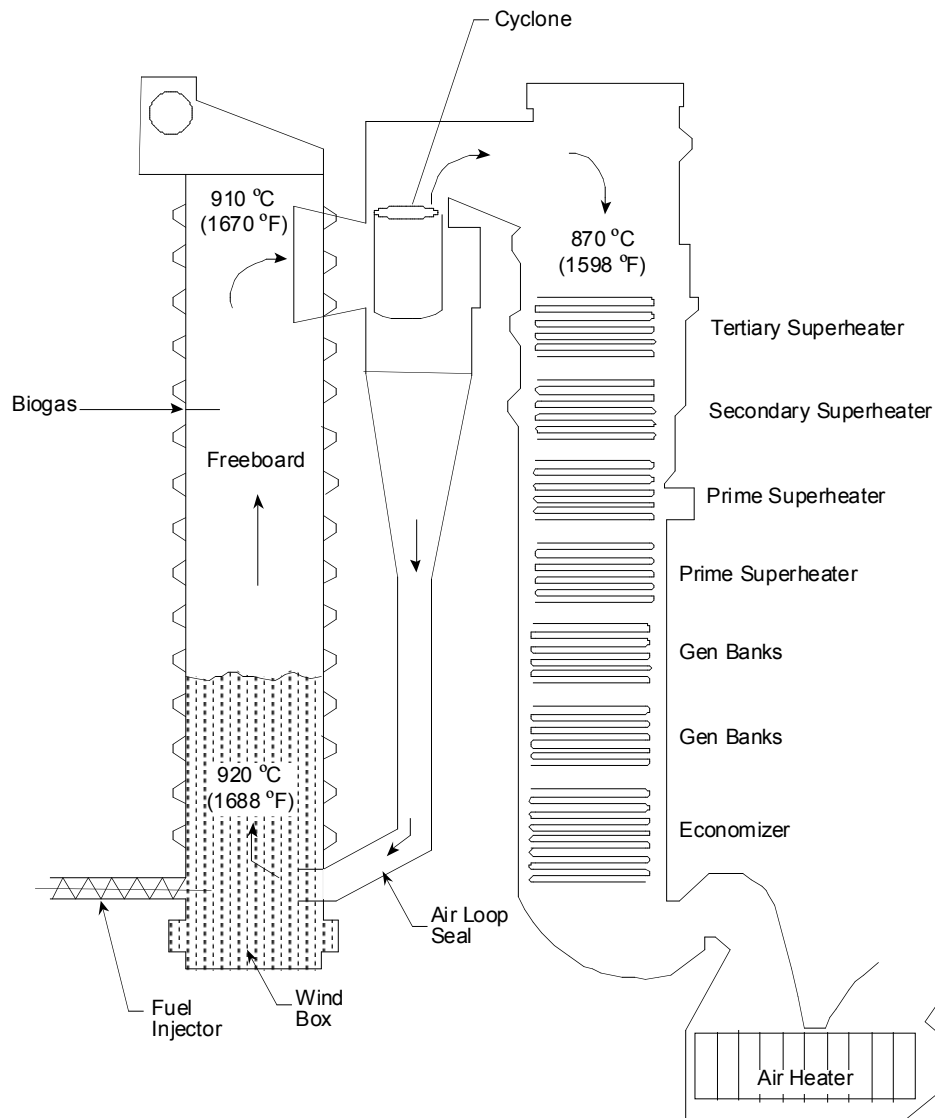
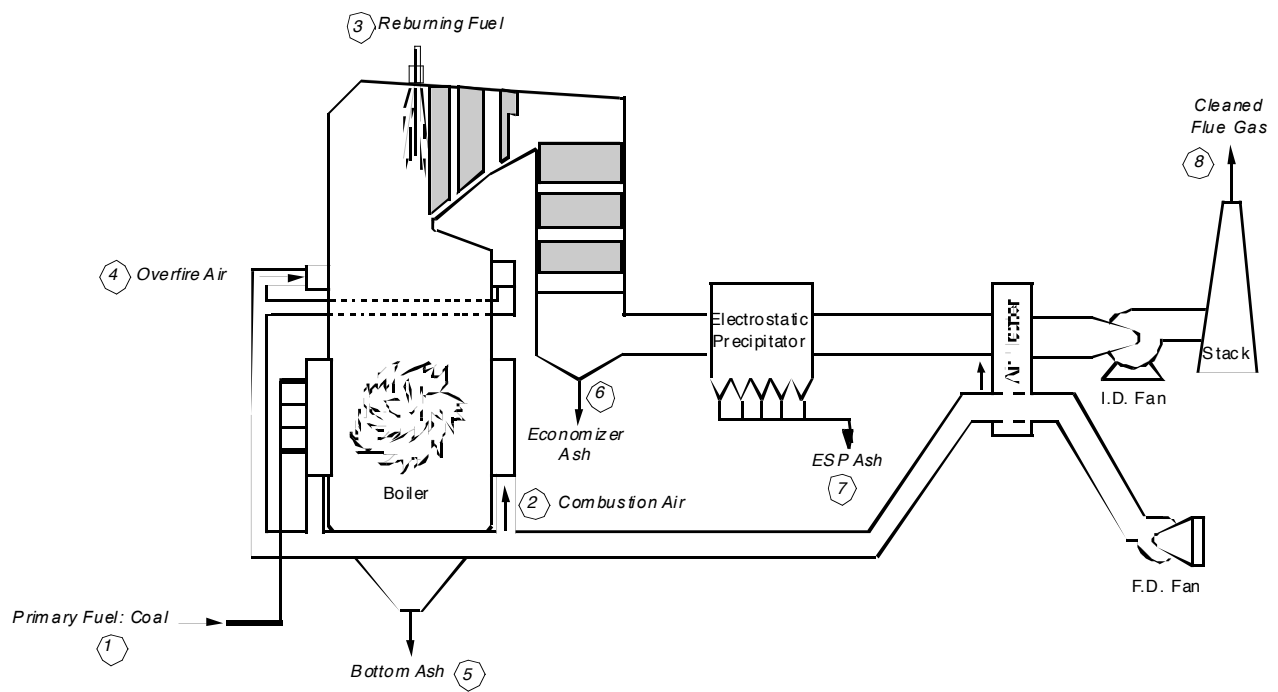


Figure 64. Application of low-T reburning to the Woodland CFB boiler.



STREAM NUMBER	1	2	3	4	5	6	7	8
DESCRIPTION	Primary Fuel: Rice Hulls	Coal Combustion Air	Reburning Fuel: Biogas	Overfire Air	Boiler Bottom Ash	Economizer Hopper Ash	ESP Ash	Flue Gas to Stack
<b>GAS SIDE:</b>								
Air (lbs/hr), dry		113,709						
Air (SCFM), dry		24,741						
Flue Gas (lbs/hr)								139,393
Flue Gas (SCFM)								28,530
<b>SOLID SIDE:</b>								
Primary Fuel (lbs/hr)	18,579		8,787					
Fuel Inerts (lbs/hr)	1,682		1,966		421	84		
Total Waste Solids (lbs/hr)	1,682				421	84		

Figure 65. Process flow diagram applying low-T reburning to Woodland boiler.

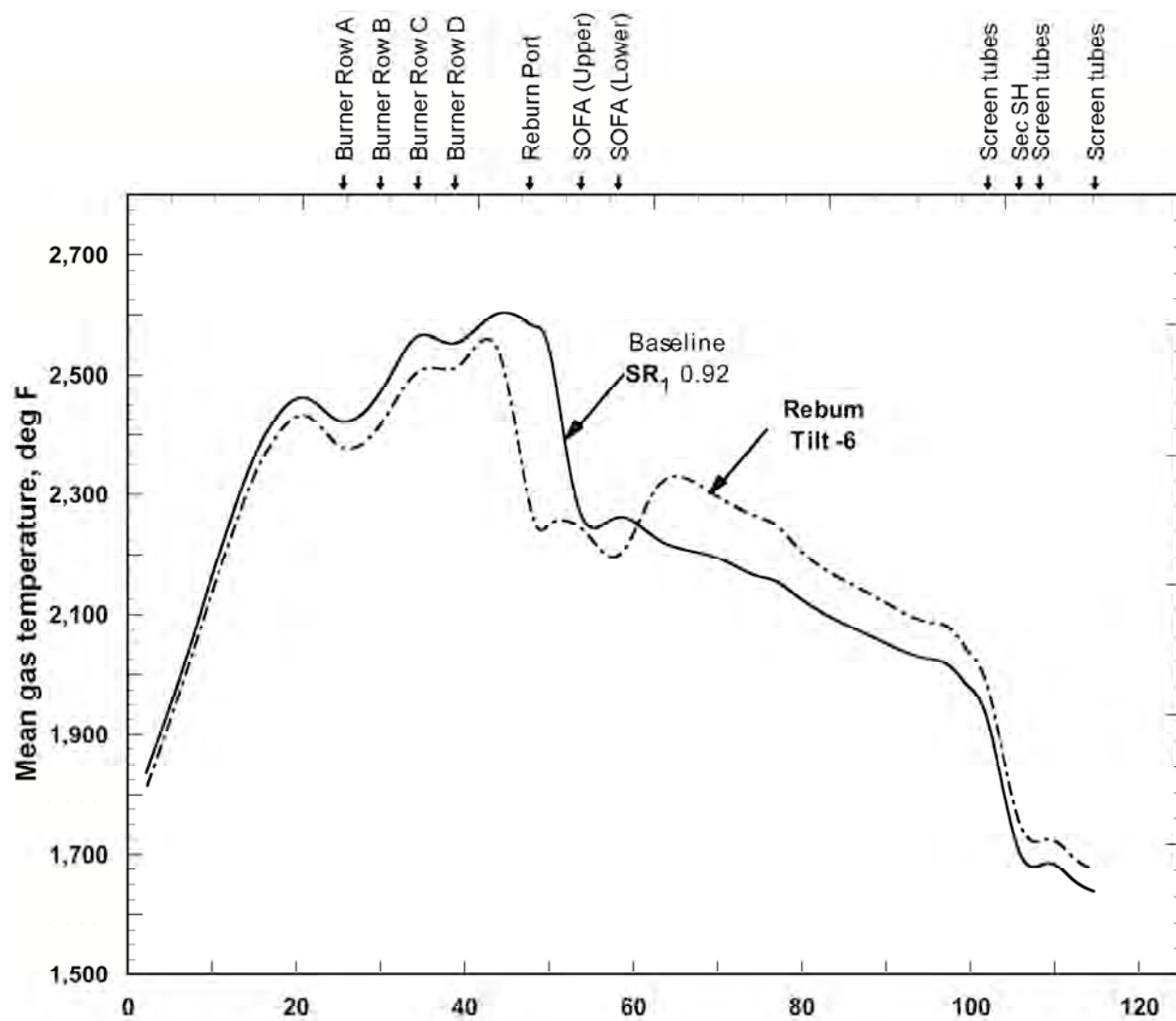


Figure 66. Predicted bulk gas furnace temperatures for full load baseline and conventional reburning conditions.

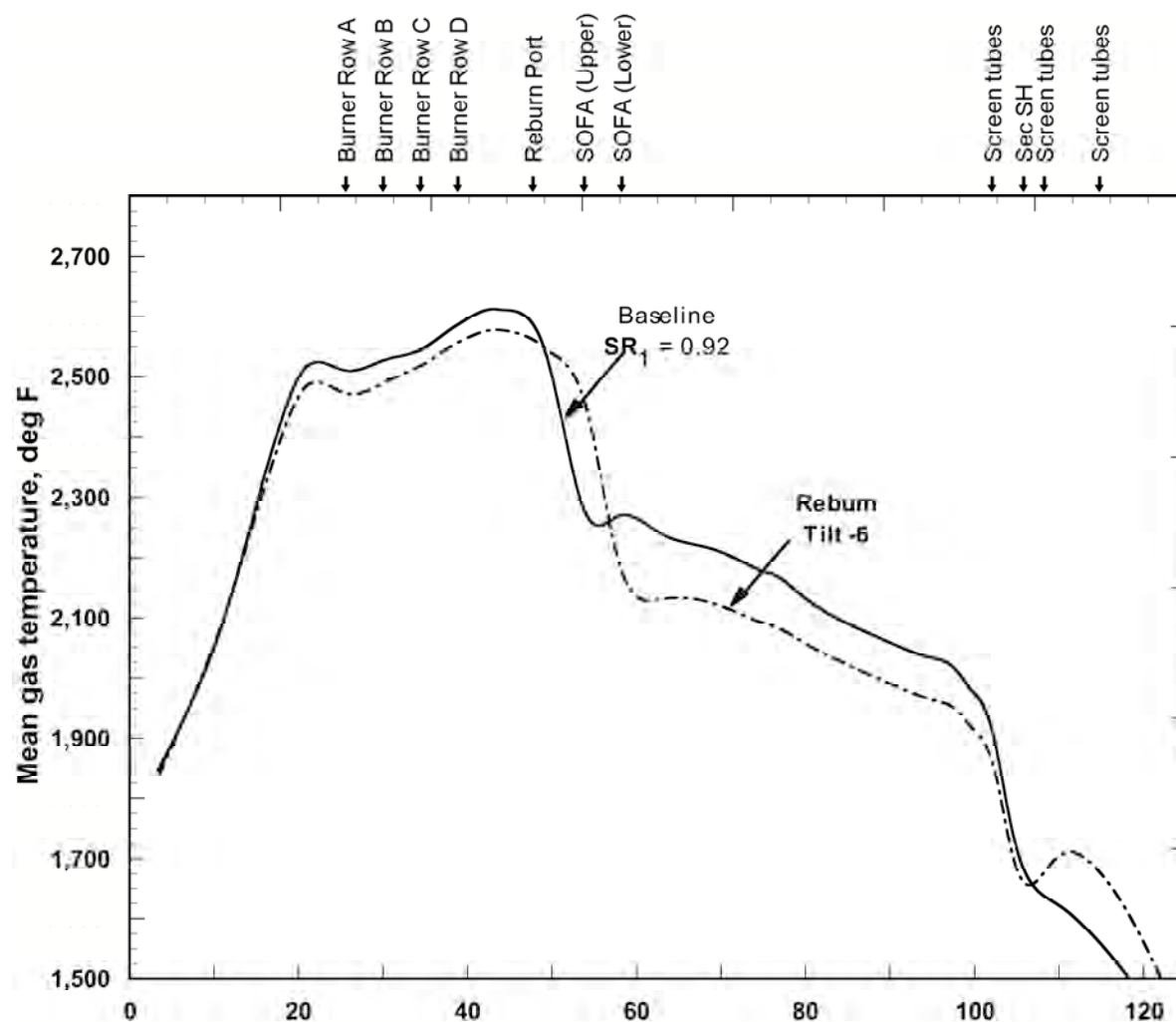


Figure 67. Predicted bulk furnace gas furnace temperatures for full load baseline and low-T reburning conditions.

Table 19. Fuel composition.

Fuel	Units	Wood Chips	Rice Hulls	Agriculture Biomass	Biogas
Site		Shasta	Wadham Energy	Woodland	
C	Wt. %	26.00	34.71	38.90	14.96
H	Wt. %	2.62	4.27	4.89	1.72
N	Wt. %	0.06	0.45	0.66	54.84
S	Wt. %	0.02	0.05	0.16	0.00
O	Wt. %	18.30	31.62	37.03	28.48
Cl	Wt. %	0.00	0.11	0.30	0.00
Ash	Wt. %	3.00	17.80	9.06	0.00
Moisture	Wt. %	50.00	11.00	9.00	0.00
Total	Wt. %	100.00	100.00	100.00	100.00
HHV	Btu/lb	4,300	6,800	7,300	2,205
Temperature	°F	---	---	---	1,500
Sp. Gr.		---	---	---	0.973

Table 20. Conventional reburn system design basis.

Site	Units	Shasta	Wadham Energy	Woodland
Load	klb/hr	170		---
Heat Input	MMBtu/hr	310	340	---
Excess Air	%	47.5	45.0	---
Main Fuel		Wood Chips	Rice Hulls	---
Reburn Fuel		BioGas	BioGas	---
Primary Zone		1.10	1.10	---
Reburn zone		0.90	0.87	---
Burnout Zone		1.48	1.45	---
Reburn Fuel	% Heat Input	25.0	25.0	---
OFA	% CA	39.2	40.3	---

Table 21. Low-temperature reburn system design basis.

Site	Units	Shasta	Wadham Energy	Woodland
Load	klb/hr	170		
Heat Input	MMBtu/hr	310	340	155
Excess Air	%	47.5	45.0	35.0
Main Fuel		Wood Chips	Rice Hulls	Agricultural
Reburn Fuel		BioGas	BioGas	BioGas
Primary Zone		1.48	1.45	1.35
Burnout Zone		1.34	1.30	1.21
Reburn Fuel	% Heat Input	12.5	12.5	12.50

Table 22. Preliminary conventional reburning injector specifications.

	Units	Shasta	Wadham Energy	Woodland
Reburning Fuel				
Injection Elevation		522'	134'-2"	---
Injection Location		Front & Rear Walls	Front Wall	---
Number of Port Openings		8	4	---
Number of Injector per Port		1	1	---
Total Number of Injectors		8	4	---
Injector Diameter	in	10.0	12.5	---
Velocity Head	in. H <sub>2</sub> O	0.8	1.6	---
Overfire Air				
Injection Elevation		535'	146'-2"	---
Injection Location		Front Wall	Front Wall	---
Number of Ports		4	4	---
Port Design		Double Concentric	Double Concentric	---
Inner Jet ID	in	12.0	12.0	---
Outer Jet ID	in	19.4	19.7	---
Velocity Head	in. H <sub>2</sub> O	1.05	0.96	---

Table 23. Preliminary low-T reburning injector specifications.

	Units	Shasta	Wadham Energy	Woodland
Reburning Fuel				
Injection Elevation		Nose	SH Entrance	Freeboard
Injection Location		Front Wall	Side Walls	Front & Side Walls
Number of Port Openings		6	8	6
		All 6 on Front Wall	4 per each Side Wall	2 per each wall
Number of Injector per Port		1	1	1
Total Number of Injectors		6	8	6
Injector Diameter	in	5.0	5.0	5.0
Velocity Head	in. H <sub>2</sub> O	5.7	3.9	1.4

Table 24. Comparison of baseline and conventional reburning performance at full load.

Parameters	Units	Baseline	Reburn 12.7% Biomass Gas
		SR1=1.00 SR2=1.00	SR1=1.00 SR2=0.91
Flue Gas O <sub>2</sub>	% dry	3.6	3.6
Primary Fuel Flow	1000 lb/hr	86.6	75.6
Reburning Fuel Flow	1000 lb/hr	0.0	66.8
Burner Tilts	deg.	-8	-6
Flue gas Temperature Leaving			
FEGT	°F	2,187	2,271
Backpass Inlet	°F	1,637	1,680
Economizer	°F	581	592
Air Preheater	°F	292	306
Flow Rates			
Main Steam	1000 lb/hr	823	827
Water/Steam Temperatures			
Economizer In	°F	378	378
Economizer Out	°F	519	527
Waterwall Out	°F	603	603
Primary SH Out	°F	829	851
Secondary SH Out	°F	1,010	1,045
Percent Carbon in ash	%	5.52	6.33
Heat Absorption			
Economizer	kW	38,559	41,121
Waterwall	kW	157,743	156,084
Primary SH	kW	53,738	57,231
Secondary SH	kW	26,470	28,330
Total Heat Absorption	kW	276,510	282,767
ASME Heat Loss Efficiency	%	88.8	87.3

Table 25. Comparison of baseline and low-T reburning performance at full load.

		Baseline (SR <sub>1</sub> = SR <sub>2</sub> = 0.92) (SR <sub>3</sub> =1.18)	Reburning 6% Biomass Gas (SR <sub>1</sub> = SR <sub>2</sub> = 0.92) (SR <sub>3</sub> =1.18)
Flue Gas O <sub>2</sub>	% dry	3.6	3.6
Primary Fuel Flow	1000 lb/hr	86.6	81.4
Reburning Fuel Flow	1000 lb/hr	0.0	31.6
Burner Tilts	deg.	-6	-6
Flue Gas Temperature Leaving			
FEGT	°F	2,180	2,096
Leaving Primary SH	°F	1,063	1,115
Economizer	°F	581	598
Air Preheater	°F	292	304
Flow Rates			
Main Steam	1000 lb/hr	820	809
Water/Steam Temperatures			
Economizer In	°F	378	378
Economizer Out	°F	527	541
Waterwall Out	°F	603	603
Primary SH Out	°F	829	884
Secondary SH Out	°F	1,010	1,057
Percent Carbon in ash	%	7.82	6.60
Heat Absorption			
Economizer	kW	40,567	44,375
Waterwall	kW	154,787	148,420
Primary SH	kW	53,334	60,890
Secondary SH	kW	26,500	24,415
Total Heat Absorption	kW	275,187	278,101
ASME Heat Loss Efficiency	%	88.42	87.87

Table 26. Projected NO<sub>x</sub> reduction at full load.

Parameters	Units	Wheelabrator Shasta	Wadham	Woodland
<b><i>Baseline</i></b>				
Baseline NO <sub>x</sub>	lb/MMBtu	0.25	0.30	0.08
<b><i>Biomass Reburning</i></b>				
Projected NO <sub>x</sub> Reduction	%	40 - 65	40 - 65	---
Projected NO <sub>x</sub> Emissions	lb/MMBtu	0.09 - 0.15	0.10 - 0.18	---
<b><i>Low Temperature Reburning</i></b>				
Projected NO <sub>x</sub> Reduction	%	20 - 50	20 - 50	20 - 30
Projected NO <sub>x</sub> Emissions	lb/MMBtu	0.12 - 0.20	0.15 - 0.24	0.056 - 0.064

### **3.8 CCG Economics Evaluation**

Economics analysis of the Close-Coupled Gasification (CCG) system was performed to determine:

- Economic size of CCG systems.
- Typical capital and operating cost of a CCG system.
- Cost effectiveness of CCG for NO<sub>x</sub> reduction compared with existing technologies.

The cost analysis included estimating: (1) CCG capital investment costs (including fuel handling and gasifier configurations) for each of the three potential host-site California biomass power plants; (2) CCG operating and maintenance costs; and (3) the CCG fuel gas cost, cost of electricity, and NO<sub>x</sub> cost effectiveness for the three base cases, as well as their sensitivity to biomass fuel feedstock delivered price and capital cost investment.

#### **3.8.1 Boiler and Gasifier Size and Performance**

The CCG system consists of a fuel handling system, gasifier, gas delivery system and a biomass boiler. Biomass plants cooperating in this study have capacities of 49 MWe (Wheelabrator, 3 boilers, 18 MWe each), 30 MWe (Wadham) and 28 MWe (Woodland). Operating characteristics of biomass plants and assumptions used in this study are shown in Table 27.

A net heat rate of 17,600 Btu/kWh is used in this study as more representative of the smaller plants in operation in California. Fuel heating value of 6,500 Btu/lb is considered here to be representative of a mixture of urban wood and agricultural fuels at 24% moisture content. Gasifier thermal efficiencies are estimated at 95%. Gasifiers are generally efficient at converting carbon in the fuel from a solid to a gas. Gasifier efficiency at 95% added to boiler efficiency of 70% results in a net thermal efficiency of 66.5%, so that a 17,600 Btu/kWh boiler may require a fuel input of 18,526 Btu/kWh to a gasifier.

At a heat rate of 17,600 Btu/kWh a 25 MWe power plant would require a fuel input of 440 MMBtu/h, or 812 dry tons per day at 6,500 Btu/lb. Since CCG tests determined that NO<sub>x</sub> could be reduced by using less than 10% producer gas in reburn configurations, the gasifier capacity should be at least 10% of boiler capacity or 2.5 MWe for a 25 MWe boiler. At a heat rate of 18,526 Btu/kWh the gasifier would require a fuel input of 46.3 MMBtu/h, or 86 tons per day. At 10% heat input a 10 MWe boiler (176 MMBtu/h) would require a gasifier with a fuel

input of 18.5 MMBtu/h or 34 tons per day. Gasifiers with capacities of 10 MMBtu/h to 100 MMBtu/h could supply most CCG application in California where power plants range from 5MWe to 50 MWe. An example of gasifier performance for three gasifier sizes is shown in Table 28.

### **3.8.2 Gasifier Type**

Several types of gasifiers can be considered for CCG applications. Figure 68, Figure 69, Figure 70, and Figure 71 represent the main technologies available for CCG. Many types of gasifiers have been used in cofiring applications. Fixed bed and fluidized bed gasifiers have operated in direct heat and power generation applications since 1979. PRM Energy Systems and their licensee PrimeEnergy have eighteen fixed bed updraft gasifiers operating primarily on rice husks in the US and Asia. About ten Bioneer fixed bed updraft gasifiers are operating in Finland and Sweden. They are now marketed by Condens Oy.

Three sizes of gasifiers appear to cover the range of biomass boilers in California: 100 MMBtu/h, 50 MMBtu/h and 25 MMBtu/h. A gasifier of 100 MMBtu/h with a 3:1 turndown has the capacity of supplying from 10% of the heat for a 50 MWe boiler to 20% of the heat for a 25 MWe plant. It would consume up to 171-tpd fuel at 6500 Btu/lb or 49,935 tpy. 100 MMBtu/h (30 MWth) is sometimes considered a minimum capacity for a stand-alone fluidized bed boiler because the cost of auxiliary equipment that supports the fluidized bed makes it difficult to economize at smaller sizes. This is the size of the gasifiers that have operated the longest on wood, urban and industrial residues and sewage sludge in North America. This capacity has also been considered for conversion of animal wastes and for cofiring biomass with coal. In a CCG application the shared cost of auxiliary equipment such as fuel handling and emissions may offset the cost of the larger system making it possible to install smaller BFB or CFB gasifiers.

Gasifiers at 50 MMBtuh (24,967 tpy) and 25 MMBtuh (9,987 tpy) were also evaluated. Fuel buyers from the cooperating biomass plants – Woodland, Wadham and Wheelabrator indicated that it would be possible to obtain lower cost fuels in these volumes. For smaller gasifiers lower cost fixed bed gasifiers and staged combustors may be more economic than bubbling or circulating fluidized beds, or the multiple reactors such as the Future Energy Resources or gasifiers with gas cleaning systems.

### 3.8.3 Capital Cost of CCG System Components

The design objective for CCG applications is to supply a biomass-derived gas for reburn, advanced reburn or cofiring in existing biomass plants. The installation goal is to be economical and share as much of the existing infrastructure as possible. The cost analysis considers the three major components of CCG: a fuel system, a gasifier, and gas delivery to the boiler.

#### *Fuel Systems*

Most CCG applications would use existing facilities for fuel receiving, processing, storage and reclaim. Plants that have a dedicated fuel, like rice hulls, may require additional fuel handling equipment for woody fuel, straw, paper, wet or processed fuels. A typical fuel flow, shown in Figure 72 consists of a truck dump, magnet, screen for oversize, stoker for open storage, drag chain reclaim and fuel in feed conveyor. A schematic of a basic fuel system is shown in Figure 73. Principal fuel systems include:

- *Truck unloading / receiving system.* For most fuels the existing wood and agricultural residue handling system would be used with additional conveyors for reclaim and transport to the gasifier. Waste paper would require receiving in an enclosed building with processing equipment. Straw would be off loaded and processed in the fuel yard.
- *Fuel storage.* A two day covered stacker reclaim is included, especially for dry bulk fuels like litter, and processed paper. The gasifier fuel is an auxiliary fuel that may be interrupted, requiring a dry surge capacity. The dry storage considered here can be internally divided between wet and dry fuels.
- *Reclaim, sizing, metal separation.* Paper wastes, straws and stalks will require sizing. Biosolids and manure solids are assumed to have been stabilized so that they would be handled like litter or compost. Biosolids, manure and paper could also be palletized.
- *Fuel drying.* Wet fuels such as biosolids, sludge and animal manures will require fuel blending or drying. Commercial gasifiers have been able to blend wet fuel with dry fuels to achieve average moisture of 20% to 35% for steady operation. A fuel dryer is considered as an option. Several fuel dryers have been used with biomass including suspension, rotary and steam drying principles. A rotary dryer is considered here.
- *Environmental control.* Fuel handling requires dust collection for most dry fuels. Wet fuels and manures may require a biological filter or other device for reducing odor and volatile organic compounds (VOC) released during processing and storage.

Table 29 is a summary of capital costs for fuel systems for a 100 MMBtu/h (200-tpd) gasifier. Capital costs were estimated from system flow diagrams, vendor quotes and engineering estimates from similar installations. Fuel processing and handling system costs can have an important impact on the total system cost for a gasifier. These systems are based on processing 200 tpd (6.5 MWe) and storing dried fuel for at least two days. Smaller systems may not cost much less due to the nature of the material being processed and the form that it is received. A 25-50 tpd gasification system may consider offsite processing in order to avoid additional capital expenditure.

### *Gasification System*

The gasification system is limited to the gasifier and auxiliary equipment. Major components include:

- Fuel feed system. Includes conveyors and transport from fuel storage to the gasifier, and fuel feed bin.
- Gasifier
- Hot gas ducting.
- Burner or injection system. Gas is supplied to the burner or injector at a duct temperature of 1,000°F to 1,200°F. Injection into the boiler is assumed to be in a burner arrangement.
- Emergency flare with safety “blocks and bleed” valves, emissions monitoring and controls.
- Motor controls and gasifier controls integrated with plant controls.
- Ash handling and media cleaning if fluidized bed.
- General plant and utilities. Includes auxiliary pumps, fans, and compressors, air or inert gas purge or as required by location, and storage vessels for media and additives.
- Gas cleaning limited to a hot gas cyclone where appropriate. Additional hot gas cleaning was not estimated in this analysis. Most installations would use hot gas directly. If ducting is adequately insulated then deposition in the ducting will be limited.

Estimates of capital costs for the gasifier are summarized in Table 30. Costs of recent proposals for fixed and fluidized bed gasifiers were reviewed and compared with budget quotations from suppliers.

The total capital cost of a 100 MMBtu/h gasifier is estimated at \$3.4 million, equal to \$626/kWe. The costs are similar to estimates for gasifiers quoted in recent combustion and

cofiring projects. Suppliers refer to a range of costs from \$300/kWe to \$1,300/kWe depending on the scope of supply. As an example of the added costs for hot gas cleaning, estimates for a 350 MMBtu/h straw gasifier including hot gas cleaning were \$1,500/kWe.

Table 31 shows gasifier costs together with fuel handling costs to estimate system costs when new fuels like straw, wet biomass, litter, biosolids or waste paper must be stored, handled or processed. A 100 MMBtu/h gasifier with minimum fuel handling might cost \$3.4 million or \$626/kWe. A cofiring application for coal or biomass where a fuel handling system is required might cost \$5.6 million equal to \$1,040/kWe. Where dry storage and additional processing, as with waste paper is required, the cost may reach \$8.4 million or \$1,562/kWe.

It is roughly, conservatively estimated that CCG system capital cost investment will range from \$900 to 1,300/kWe for the CCG systems that would be applied to the three host site boilers.

#### **3.8.4 CCG Operating Costs**

Manpower requirements for a 100 MMBtu/h facility are primarily in fuel processing and maintenance, which are assumed to be costs shared with the host power plant. Attention from one operator and one maintenance person would be required per shift for the gasifier. If a 100 MMBtu/h gasifier were to be operated as a separate power generator it would require two operators and one maintenance person per shift for a total of 15 based on five-shift rotation.

Utilities supplied to the gasifier include electric power, cooling water, plant water, portable water and natural gas. Plant and instrument air are provided by dedicated onsite equipment. Electrical consumption for a gasifier is constant consisting of gasification air and auxiliary equipment. For the purpose of this analysis, operating costs are assumed to be 3% of capital costs.

#### **3.8.5 Economic Analysis Procedure**

The economic performance of the Close-Coupled Gasifier (CCG) has been assessed by considering the effect of CCG installed capital cost, incremental boiler and CCG system operating and maintenance costs, and CCG biomass fuel costs, and then by applying an economic model to the three base cases. The model estimates the annualized (levelized) total cost of the produced CCG fuel-gas (or the equivalent cost of electricity produced from the CCG

fuel-gas). It follows a format that is similar to those used by the Electric Power Institute and the U.S. DOE for evaluating the cost of electricity produced by competing technologies.

### **3.8.6 CCG Fuel Gas Cost and Cost of Electricity**

The cost of CCG gas or electricity is influenced by the cost of fuel, system costs including shared balance of plant costs, recurring costs for labor and consumables and environmental costs, especially where components of the CCG fuel may require special ash disposal or handling. Fuel gas costs were studied by determining the range of capital costs necessary to produce fuel gas at competitive prices. Table 32 and Table 33 list the major economic assumptions used to generate gas and electricity costs.

The effect of CCG capital cost investment and biomass fuel cost on the cost of fuel gas from the gasifier and the contributing cost on electricity from the gasifier are shown in Figure 74 through Figure 79.

Figure 74 shows the impact of the capital cost investment and loan repayment term on the cost of the gasifier fuel gas. Biomass boiler plant operators indicate that it is particularly important that the gasifier has a short payback period due to the short length of current power contracts, high uncertainty about future electricity contracts, and fuel subsidies and costs. This analysis shows that reducing the payback term increases the fuel gas costs significantly but may fall within the fuel gas cost targets of California biomass plants.

Figure 75 shows the influence of biomass fuel cost on the cost of fuel gas produced by the gasifier.

Total fuel gas cost is shown in Figure 76 (the sum of Figure 74 and Figure 75) for a 10-year repayment term on the capital cost investment. The CCG capital cost investment range for the host-site boilers is included on the figure. Common woody biomass fuel costs are in the \$1.00 – 2.00/MMBtu range (\$15 – 30/ton fuel). Thus, a CCG fuel gas production target of \$1.00/MMBtu or less is desirable for the plant to remain cost competitive. CCG systems for the Wadham and Woodland boilers (CCI of \$1,300/kWe) are projected to achieve a fuel gas cost of \$2.75/MMBtu for biomass fuel at \$10/ton; and a fuel gas cost of \$1.00/MMBtu with CCG biomass fuel at a cost of -\$10/ton (fuel at a negative, tipping fee cost of \$10/ton). No-cost (or tipping fee, negative cost) biomass fuel may include urban wastes (such as waste paper or plastics), sewage sludge, potentially subsidized fuels such as rice straw, and low value agricultural residues such as shells and pits. For the Wheelabrator boiler (CCI of \$900/kWe), a

fuel gas cost of \$1.00/MMBtu is achieved for a CCG biomass fuel of -\$5/ton. The average tipping fee at California materials recovery facilities is \$45-\$50 per ton. Other costs of using alternate fuels that are not apparent but can be significant are procurement and management.

The base gasifier cost is used without the incremental costs for storage or drying. As a base case, it is assumed that the operator can blend fuels into the gasifier to maintain operable moisture content. Gasifiers are fired with paper and other light residues on a reliable basis. In practice a blend of urban and other biomass is used to provide the gasifier with a steady flow. During the harvesting and processing seasons agricultural residues are sometimes available at low cost, and throughout the year some urban and industrial residues are disposed of at a fee. Pits nuts and shells for example can require no covered storage. However if large quantities are to be stockpiled then odor control and covered storage may be required. A biomass plant ordinarily might be limited by regulation or boiler conditions to 5,000 tpy of pits, nuts or shells. That quantity could be increased to 25,000 tons if it is obtained during the processing season and gasified at 86 tpd in a 50 MMBtu/h (\$794/kWe) CCG. A fuel cost of \$5/ton would result in a fuel gas production at less than \$1.50/MMBtu.

Figure 77 and Figure 78 show the effect of CCG capital cost investment, repayment term, and non-fuel O&M and fuel on the cost of electricity produced. The cost of electricity is proportional to unit capital cost and dependent on repayment terms.

Figure 79 (the sum of Figure 77 and Figure 78) shows the total cost of CCG electricity as a function of gasifier cost and biomass fuel cost, based on a 10-year repayment term. For a CCG biomass fuel cost of \$10/ton (\$1.00/MMBtu) at the host sites, the CCG cost of electricity is between approximately \$0.04-0.05/kWe. For a no-cost biomass fuel, the CCG cost of electricity is about \$0.023-0.033/kWe. For comparison, for a typical biomass boiler, electricity is produced at about \$0.018/kWe with biomass fuel at a cost of \$1.00/MMBtu. Assuming no NO<sub>x</sub> reduction credit (i.e., for plants interested only in utilizing available low-grade fuels and have no need for additional NO<sub>x</sub> control from their boilers), biomass boilers within the size range of the three host-sites retrofitting CCG systems to their boilers could be cost competitive if they utilize fuels for CCG at no cost or with tipping fees.

### **3.8.7 Comparison of CCG NO<sub>x</sub> Control Costs with Current NO<sub>x</sub> Control Costs**

The cost of fuel gas and cost of electricity from CCG appears favorable in the capacity ranges suitable for NO<sub>x</sub> control. The economic model was extended to estimate the cost of NO<sub>x</sub>

control compared with conventional NO<sub>x</sub> control systems. Fuel N-content is an additional factor to evaluate. This study found underutilized sources of biomass in California that contain high nitrogen, which could be used in biomass plants by employing CCG.

### ***Nitrogen Content of Biomass Fuels***

Urban and industrial wood wastes are the principal fuels fired in California biomass plants. Wood from mill residue normally contains very low nitrogen (<0.5%). Urban wood is generally less than 1.5% N. The generally low nitrogen content in wood wastes is reflected by the low NO<sub>x</sub> emissions for most biomass plants and the large number of biomass plants that can achieve NO<sub>x</sub> emission limits with little or few control devices. These sources of wood are becoming scarce and face competition from other uses, notably solid wood panels. Sources of biomass fuels that are available to plants seeking new fuels or new capacity are generally urban and agricultural residues with high nitrogen contents. Agricultural and forest residues that contain higher nitrogen (0.5% to 1%) such as pits, nuts and shells, are sometimes limited by air quality permits to less than 5% of the fuel stream. Table 34 shows a sample of N-content in biomass fuels. Biomass plants without controls blend fuels to achieve NO<sub>x</sub> standards. Those with Selective Non-Catalytic Reduction (SNCR) systems find that ammonia consumption increases with increased firing of these residues. CCG offers a means for increased firing of high nitrogen fuels, or a way of permitting firing high nitrogen fuels without installing NO<sub>x</sub> control equipment. CCG gas fired at the GE EER's pilot facility showed no increase in boiler NO<sub>x</sub> due to the nitrogen in almond shells, which have two times the concentration of typical California biomass plant fuels.

Table 34 compares the nitrogen content of several California biomass fuels that have been identified in this study as opportunity fuels. Wood waste fuels have concentrations of 0.1 to 0.3 lb/MMBtu. Blended fuels at urban wood fired biomass plants have a nitrogen concentration of 0.3 lb/MMBtu to 0.5 lb/MMBtu. Plants firing agricultural residues like pits and almonds have a higher concentration of 0.6 to 0.9 lb/MMBtu. Almond shells and hulls at 1.0-1.4 lb/MMBtu have a strong influence on nitrogen at 2 to 3 times the concentration of a typical fuel mix. Poultry litter and sewage sludge have concentrations more than 12 times biomass fuel mix at 6 lb/MMBtu.

Fuels with greater than 0.5% nitrogen represent a gross potential of 14.8 million tons per year, or about 1,500 MWe capacity. Existing biomass plants would require SNCR controls to fire

more of these fuels. The most accessible of these fuels may be: forest residues (5 million bdt) due to fire management; livestock manures and litter (2.5 million bdt of which 0.7 million bdt is litter) due to federal regulations on nutrient management in confined feeding operations (CAFO); unused urban wood and yard waste (1.9 million bdt); unused pits nuts and shells (almonds, walnut, fruit pits, rice hulls, cotton gin wastes = 0.6 million bdt); and sewage sludge (0.6 million bdt). The cost of NO<sub>x</sub> control is avoided if CCG is used as a means of introduced these wastes to a boiler as a reburn fuel and the gasification cost is equal to the cost of alternate fuels.

### ***Cost Effectiveness of Conventional NO<sub>x</sub> Controls Used by Existing Biomass Boiler Operations***

Selective Non-Catalytic Reduction (SNCR) is typically used to control NO<sub>x</sub> from approximately 20 currently operating biomass boilers in the State of California. SNCR NO<sub>x</sub> control efficiency is typically 30-50%. The cost effectiveness of SNCR for NO<sub>x</sub> control on biomass boilers is estimated to be 550-700 \$/ton NO<sub>x</sub> reduced, depending primarily on the uncontrolled NO<sub>x</sub> level, and the ammonia reagent type and cost.

### ***Close-Coupled Gasifier NO<sub>x</sub> Control Costs***

CCG system costs that are attributable to NO<sub>x</sub> control include:

- Gasifier capital equipment purchase and installation cost (amortized).
- Gasifier non-fuel O&M requirements.
- Difference between the cost of the gasifier fuel and the cost of the fuel to the main boiler that is displaced by the gasifier. For example, if the cost of the gasifier fuel is the exact same as the cost of the main boiler fuel, then there is no fuel cost penalty or benefit associated with the gasifier -- with or without the gasifier, the total system fuel cost is the same. Alternatively, if the gasifier is able to process larger amounts of lower cost, lower quality fuels compared with what would be acceptable to be used in the main boiler, total system fuel costs with the gasifier will actually be reduced. This reduction in fuel cost due to the gasifiers' ability to process lower cost fuel is directly attributable to the NO<sub>x</sub> control cost.
- Since most large plants have SNCRs, the ammonia cost is the principal savings attributable to CCG.

Figure 80 shows estimated CCG NO<sub>x</sub> control cost effectiveness, for various CCG capital cost investments, as a function of CCG fuel cost differential (relative to biomass boiler fuel cost). For low cost fuels, the CCG NO<sub>x</sub> cost effectiveness compares very favorably with that of SNCR; SNCR NO<sub>x</sub> control cost is estimated at about \$800 – 1,000/ton NO<sub>x</sub> reduced. For the Wheelabrator CCG (with a CCI of about \$900/kWe) and a CCG biomass fuel that is \$12/ton cheaper than the standard main boiler fuel, the CCG NO<sub>x</sub> control effectiveness is \$600/ton or about 25% less than SNCR. This indicates that when NO<sub>x</sub> control is of interest (which is expected to be for most plants as NO<sub>x</sub> control regulations become more stringent), using CCG with low-grade, low-cost biomass fuels could be cost effective in comparison to conventional NO<sub>x</sub> control technologies.



156



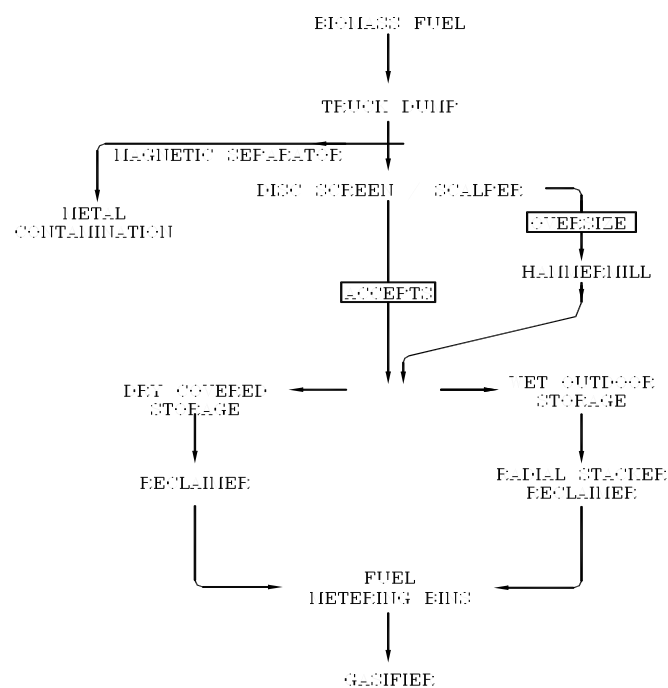


Figure 72. Biomass Fuel Flow

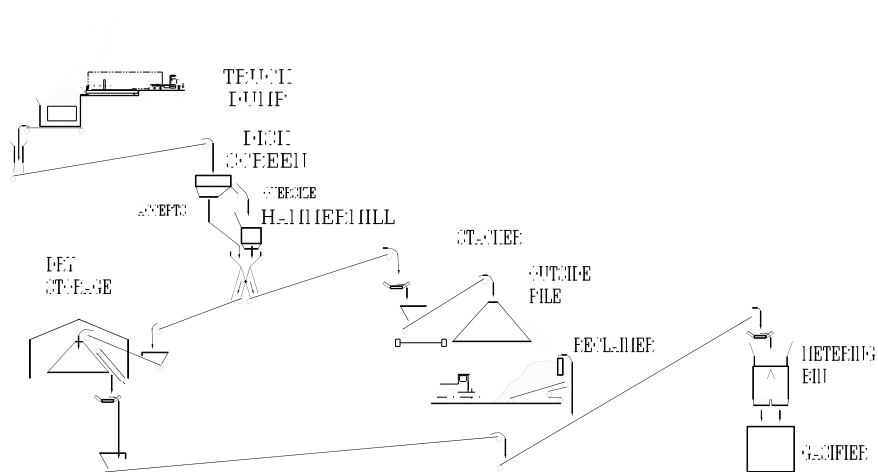


Figure 73. Biomass Fuel System

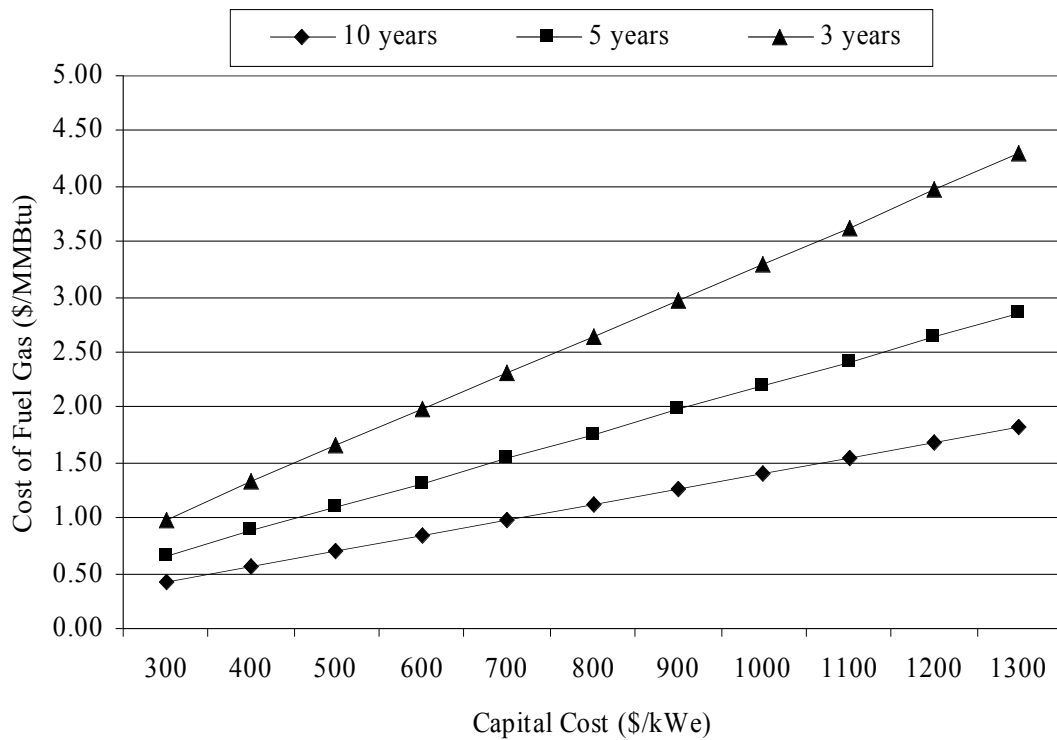


Figure 74. Effect of repayment term (y) and cost of capital and non-fuel O&M (\$/kWe) on cost of fuel gas from gasifier during term of capital repayment. Does not include biomass fuel cost.

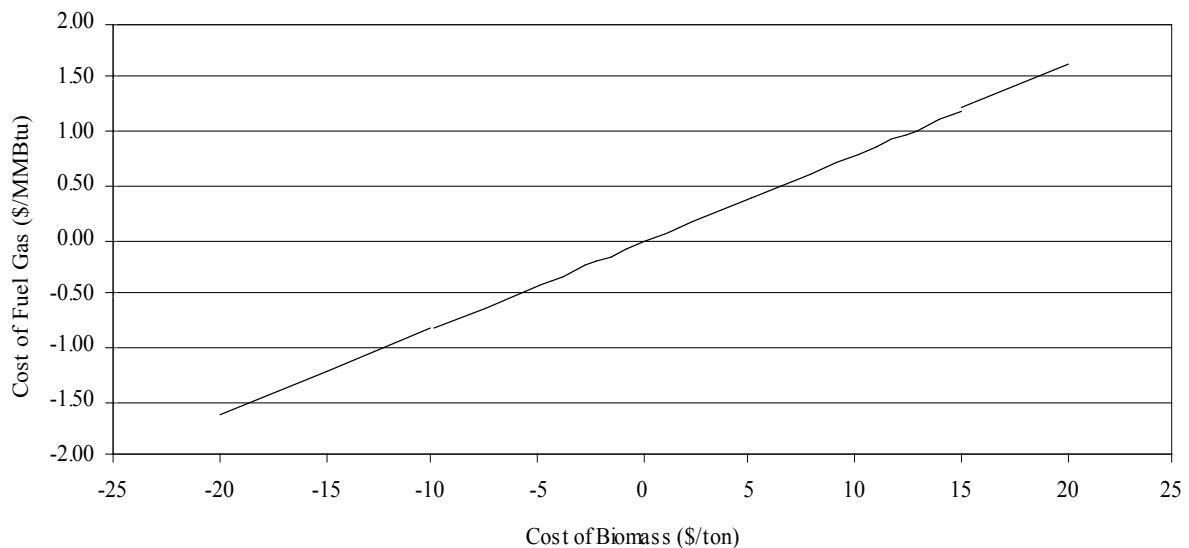


Figure 75. Effect of biomass fuel cost (\$/ton) on cost of fuel gas from gasifier. Does not include capital or non-fuel O&M costs.

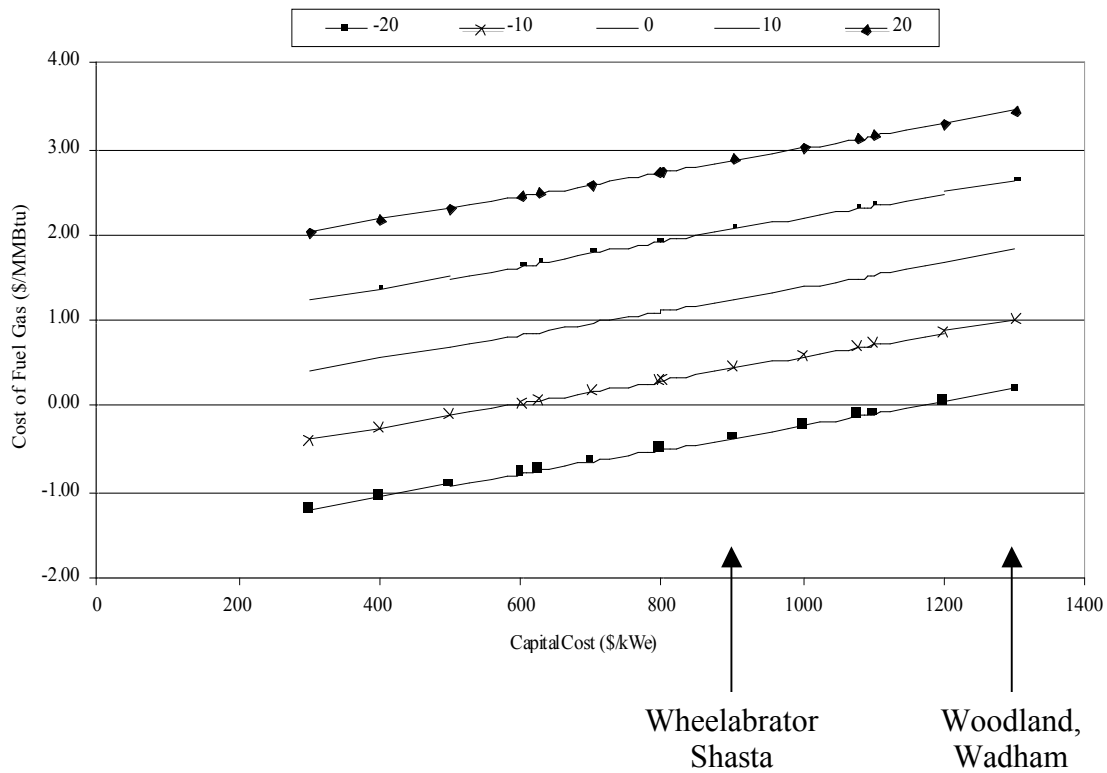


Figure 76. Cost of fuel gas (\$/MMBtu) with a 10-year repayment term at various capital costs (\$/kWe) and biomass fuel costs (\$/ton).

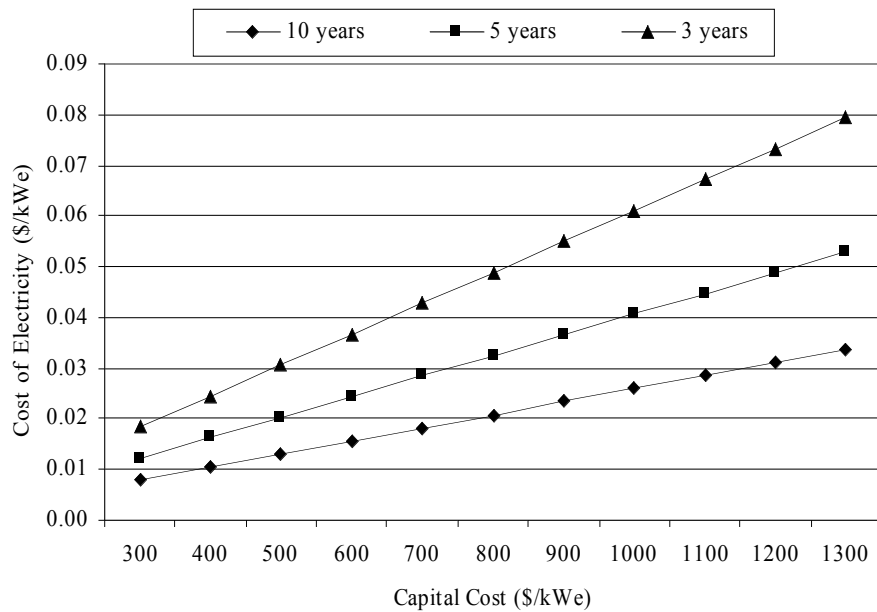


Figure 77. Effect of CCG capital and repayment terms on the cost of electricity.

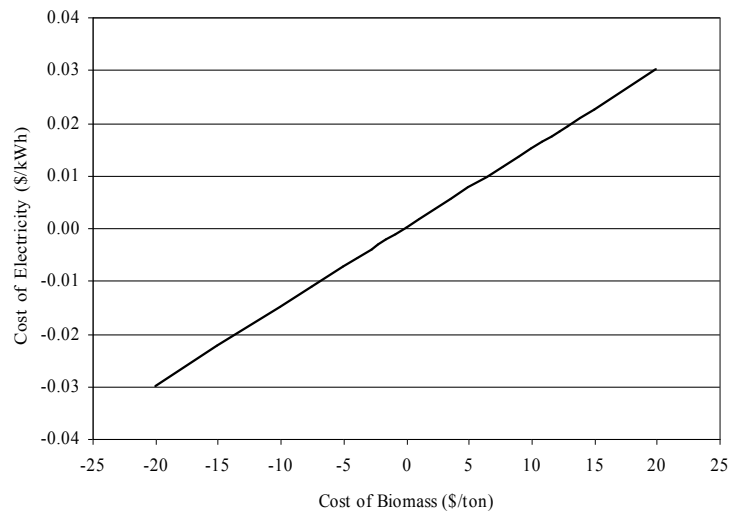


Figure 78. Effect of cost of biomass fuel (\$/ton) on cost of electricity from gasifier. Does not include capital or non-fuel O&M costs.

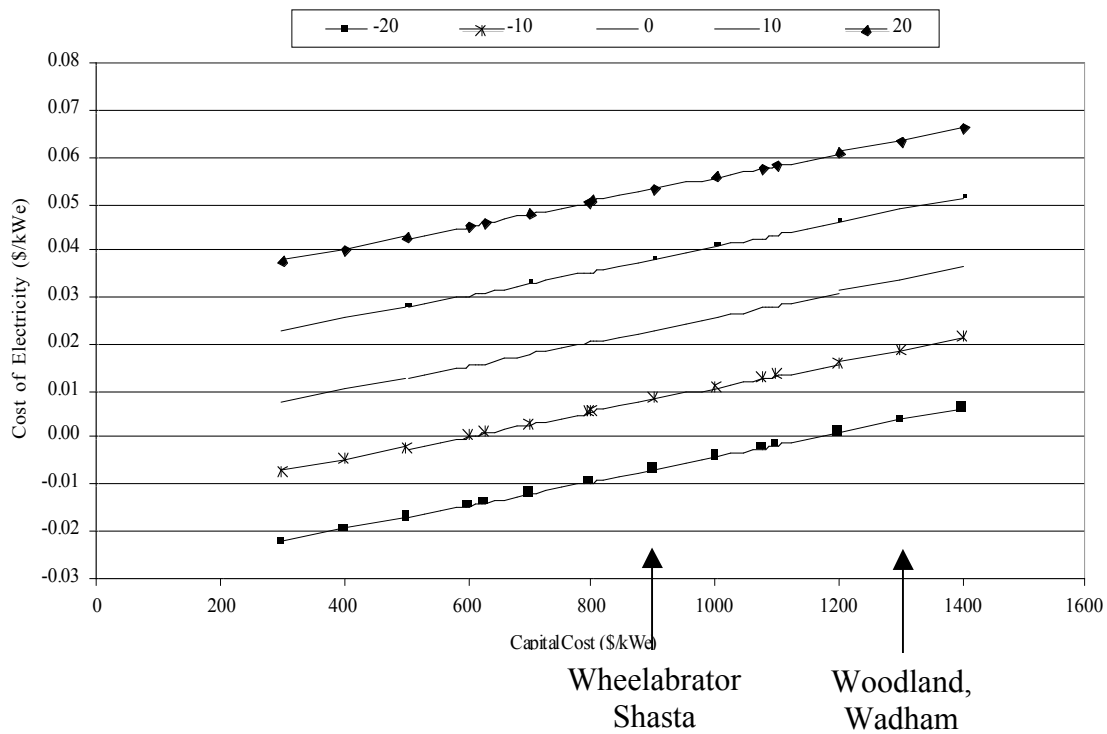


Figure 79. Effect of capital cost and fuel cost on the cost of electricity.

Gasifier provides 10% of total system heat input  
 Baseline NO<sub>x</sub> : 0.3 lb/MMBtu  
 Gasifier reburn : 60% NO<sub>x</sub> control

Gasifier O&M (non-fuel) : 3% cap / yr  
 Fuel Heating Value : 6,500 Btu/lb  
 Plant Efficiency : 17,600 Btu/kWh  
 Plant Online Capacity Factor : 80%  
 10 year loan, 12% ROR (Cap Recovery Factor : 17.2%)

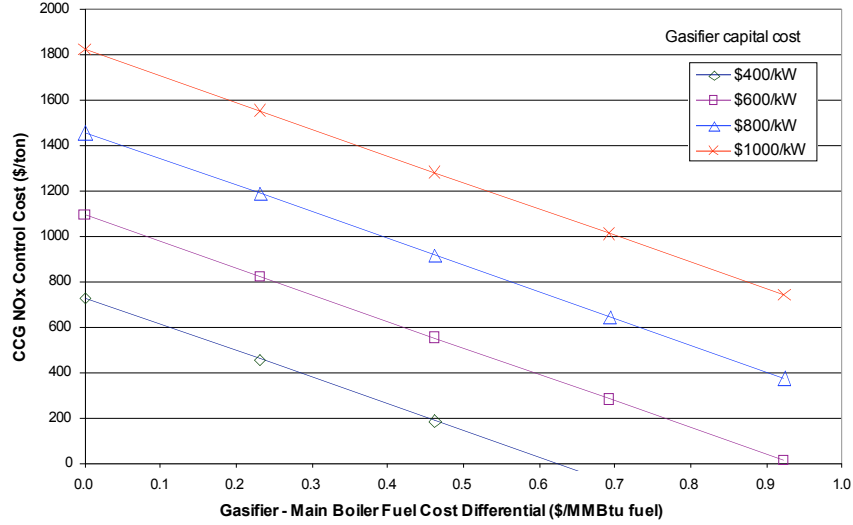


Figure 80. NO<sub>x</sub> control cost effectiveness for CCG.

Table 27. Operating assumptions: performance of biomass plants.

Gross generation	MWe	50	25	10
Capacity factor	%	80	80	80
Boiler heat rate	Btu/kWh	17,600	17,600	17,600
Heat Input from Fuel	MMBtu/h	880	440	176
Electricity production	MWh/year	350,400	175,200	70,080
Fuel heating value	Btu/lb	6,500	6,500	6,500
Fuel consumed	Tons/day	1,625	812	325
	Tons/year	474,388	237,194	94,878

Table 28. Gasifier size and performance.

Gasifier Required Capacity	MWe	5	2.5	1.0
Gasifier Size	MMBtu/h	100	50	25
Gasifier-Boiler heat rate	Btu/kWh	18,526	18,526	18,526
Heat input from Fuel	MMBtu/h	92.6	46.3	18.5
Capacity factor	%	80	80	80
Electricity Production	MWh/year	35,040	17,520	7,008
Fuel heating value	Btu/lb	6,500	6,500	6,500
Fuel required	Tons/day	171	86	34
	Tons/year	49,935	24,967	9,987

Table 29. Capital costs (\$1,000) of fuel systems for 200 TPD (100 MMBtu/h).

Component	Fuel Receiving, & Handling	Dry Storage	Fuel Dryer	Straw Processing	Waste Paper Processing
Civil/Structural	240	375	41	157	708
Process Equipment	1,183	593	584	251	1,761
Electrical and Controls	228	109	109	116	217
Total Direct Costs	1,651	1,077	734	524	2,686
Engineering and other indirect	134	57	188	67	218
Total Construction Cost	1,785	1,134	922	591	2,904
Contingency and unlisted items	447	283	277	59	727
Total Capital Cost	2,232	1,417	1,199	650	3,631

Table 30. Capital costs (\$1,000) of gasifiers.

Capacity	100 MMBtu/h	50 MMBtu/h	25 MMBtu/h
Civil/Structural	98	50	50
Process Equipment			
Gasifier, auxiliaries	1,518	940	550
Hot gas duct, burner	654	408	324
Misc., mechanical install	156	114	85
Total Process Equipment	2,328	1,462	959
Electrical and Controls	76	75	65
Total Direct Costs	2,502	1,587	1,074
Engineering & other indirect	203	128	88
Total Construction Cost	2,705	1,715	1,162
Contingency & unlisted items	676	429	290
Total Capital Cost	3,381	2,144	1,452
Btu/kWe	18,526	18,526	18,526
kWe/h	5,398	2,699	1,349
\$/kW	626	794	1,076

Table 31. Gasification system costs (\$ 1,000) for 100 MMBtu/h (200 tpd).

	Gasifier	Straws and Stalks	Wet Biomass	Litter, bio- solids <sup>/1</sup>	Gasifier and Fuel Handling	Waste Paper
Gasifier	3,381	3,381	3,381	3,381	3,381	3,381
Fuel Handling					2,232	
Dry Storage				1,417		1,417
Dryer			1,119			
Straw Processing		650				
Waste Paper						3,631
Total	3,381	4,031	4,500	4,798	5,613	8,429
\$/kW <sup>/1</sup>	626	747	834	889	1,040	1,562

/1 5398 kW at 18,526 Btu.kWe

Table 32. Assumptions for the economics analysis used in CCG capital cost estimates.

Plant Heat Rate (Btu/kWh)	18,526
Capacity Factor (% Online)	80
Capital Costs (\$/kWe)	300-1300
O&M Costs (Non-fuel, % of capital)	3
Fuel Higher Heating Value (Btu/lb)	6,500
Fuel Costs (\$/ton)	-20 to +20
Rate of Return (%)	12
Years Financed	10, 5, 3

Table 33. Assumptions for the economics analysis.

Interest rate (%/y)	12	12	12
Term (y)	10	5	3
Capital Recovery Factor, CRF (1/y)	0.177	0.277	0.416
Non-fuel O&M (% of Capital Cost)	3	3	3
Heat rate (Btu/kWh)	18,526	18,526	18,526
Heat rate (MMBtu/kWh)	.0185	.0185	.0185
Capacity factor (%)	80	80	80
Hours per year (h/y)	7008	7008	7008
Heating value of fuel (Btu/lb)	6500	6500	6500
Heating value of fuel (MMBtu/ton)	13	13	13
Gasifier efficiency (--)	0.95	0.95	0.95

Table 34. Nitrogen in biomass fuels.

Fuel	% N	HHV Btu/lb	N Lb/MMBtu	Index	MMbdt/year
Urban wood-ag blend	0.41	8,815	0.47	1	
Wood-pit blend	0.65	8,450	0.77	1.64	
Rice Straw	0.87	8,123	1.07	2.28	1.00
Almond hulls	1.13	8,119	1.39	2.99	0.70
Almond shells	0.76	8,387	0.95	2.03	
Walnut shells	1.53	9,451	1.60	3.40	0.07
Poultry/turkey litter	3.01	4,934	6.10	12.98	0.70
Sewage sludge	5.00	8,000	6.25	13	0.60

Sources: Appendix D Nitrogen in California Fuels; Resource Assessment Task 2.1

### **3.9 Market Evaluation**

A review was made of the production readiness of the CCG technology that considers the current state of gasifier technology and applications. Markets for CCG were assessed considering opportunities in coal and biomass boilers in California and the United States. Finally, market drivers for NO<sub>x</sub> control were evaluated including pressures for NO<sub>x</sub> control and the availability of low grade, low cost fuels that cannot be burned in existing boilers. The benefits of the CCG technology are twofold:

- NO<sub>x</sub> reduction
- Use of alternate or lower cost fuels

Early in the program, industry cooperators stated that in the current economic conditions, the potential to use alternate, low-cost fuels is of slightly more interest than NO<sub>x</sub> reduction. Despite its promise, CCG technology cannot single-handedly help the biomass industry rise above its current challenges. Continued technical development and demonstration, coupled with economic incentives for use of renewable fuels is the key to opening the market for the CCG technology. An assessment of California's currently operating and idle biomass-to-energy facilities has been conducted to identify the potential sources of plants that could be retrofitted with CCG technology and their similarity to development units with CCG. The importance of NO<sub>x</sub> reduction and the associated regulatory and economic issues are potential driving forces that could accelerate the adoption of new technologies such as CCG, and have been evaluated. Alternative fuel types vary in their price, availability, and compatibility with CCG technology. Combining these three criteria, the most suitable fuel types have been specified, and the economic threshold for adoption of CCG technology has been identified.

#### **3.9.1 State of the Industry: California Biomass Boilers**

The Integrated Solid Waste Management Board (IWMB) estimates that there are approximately 26 operating biomass-to-energy facilities in California, with a total generating capacity of 550 MW, as shown in Table 35. An additional 17 plants may be sitting idle.

Several plants returned to service under short-term contracts following the increase in electricity rates in 2001. A list of Pacific Gas and Electric contracts for 2001 was reviewed along with other reference data on California plants to determine the type and size of the potential NO<sub>x</sub> control market. Results in Table 36 show that as of July 2001, eighteen of 24 plants were

spreader stoker traveling grates; five of 24 were circulating fluidized beds, one is a fluidized bed and one is a suspension-fired plant. The table also shows that 45 of the 60 plants operating in the 1990s were spreader stokers with traveling grates, 10 were bubbling fluidized beds, seven were circulating fluidized beds and 1 was a suspension fired burner.

Plants cooperating with GE EER in this project represent the major types of biomass boilers. The IWMB further identifies the fuels used by biomass facilities as belonging to four categories: wood processing residues, in-forest residues, agricultural residues, and urban wood residues (Table 37). The 2001 report notes that compared with 1990 consumption, 3 million tons of residues are not being consumed. Agricultural residues are being open burned, forest residues are being open burned and more residues are being land filled, or, in some cases used as alternative daily cover rather than being used as fuels. The IWMB study identified a “cost shift” comparing the average revenue from electricity sales to the average cost of producing electricity, provided in Table 37. They derived a net difference of \$0.012- 0.024/kWh with the greatest loss being for in-forest residues. In terms of fuel cost, this equates to a loss of \$12 to \$24 per ton since each \$10 per ton paid for fuel adds about \$0.01/kWh to the overall cost of producing electricity.

The IWMB study found that most biomass facilities are in a weak financial position. The study recommended long-term contracts, minimum purchase requirements, amendment to the Section 45 tax credits and financial incentives to bring plants online in order to stimulate the industry. Most incentives imply a fuel cost reduction of \$10-\$20/ton (\$0.01-0.02/kWh).

IWMB study shows the importance of identifying circumstances that would allow CCG to pay for itself under terms acceptable to industry. A gasifier contributing 5 MWe consumes 50,000 tpy of fuel. If a gasifier could allow the use of a lower-cost or subsidized fuel, a cost savings of \$10/ton (\$0.67/MMBtu, \$0.01/kWh) might be realized, justifying an investment of \$3 million or more. Savings could also be realized for a longer-term investment.

### **3.9.2 NO<sub>x</sub> Reduction**

NO<sub>x</sub> control in California biomass plants is usually achieved through Selective Non-Catalytic Reduction (SNCR) using ammonia or urea. A review of permit and compliance data for nineteen plants showed that many of the 26 biomass plants still in operation (and some of the 17 power plants that have been idled) have permit and compliance levels lower than the generally-

accepted 0.30 lb NO<sub>x</sub> /MMBtu (Table 38). Typical uncontrolled NO<sub>x</sub> levels are about 0.22 lb/MMBtu. NO<sub>x</sub> permit levels range from 0.08 lb/MMBtu to 0.30 lb/MMBtu.

Plants that were built during the standard offer # 4 (SO#4) period (1985-1990) use ammonia or urea systems for NO<sub>x</sub> control. A target for CCG retrofitting would be those plants that have a higher-cost urea system or that want to avoid the hazardous handling of ammonia. Although biomass plants complain about the hazards of ammonia and the problems associated with ammonia systems, in general they have adapted to operation; currently, there is no strong incentive for replacing them with an alternate system such as CCG. Until CCG is demonstrated at the industrial scale, or unless incentives are in place for biomass fuel usage, ammonia systems remain a viable option for NO<sub>x</sub> control.

It would appear that the primary benefit of CCG to existing plants is either to reduce NO<sub>x</sub> emissions to comply with increased regulation, or to increase the capacity of existing plants. Some older plants may be eligible for NO<sub>x</sub> control using CCG if they change fuels or increase capacity. Some cell furnaces have higher NO<sub>x</sub> permits than CFB's, FB's or stokers. In particular, some plants have NO<sub>x</sub> permits above 0.50 lb/MMBtu, including about 10 of the plants reviewed for this study.

### **3.9.3 Alternative Fuels**

Biomass plants participating in this study expressed from the beginning that the priority was not primarily for NO<sub>x</sub> control but for the potential to burn fuels such as rice straw that they are unable to burn in their existing boilers. California biomass plants represent combustion technologies suitable for a wide range of fuels. Some fuels, especially those with high fuel-bound nitrogen like rice hulls and rice straw, pits and shells cannot be burned in substantial volumes in existing spreader stokers or fluidized beds without incurring problems due to the alkali and nitrogen content. Experience at California plants since 1986 has shown that some of these fuels can easily be used to provide up to about 5% of fuel input without incurring operational or emission problems (NO<sub>x</sub>, slagging or fouling). CCG offers an opportunity through gasification and staged combustion to enable these fuels to be used to provide a larger fraction of the heat input.

Cost savings from alternate fuels can be significant. If current fuels average \$1.50/MMBtu or \$20/dry ton and alternate fuels are delivered at \$0.50/MMBtu or \$7.50 per ton then the annual savings could be \$1.00/MMBtu or \$15/ton, equal to an offset of \$0.015/kWh.

Opportunity fuels valued from \$0.0/MMBtu to \$2.50/MMBtu or about \$0/ton to \$36/ton were considered for this study. CCG could increase the quantity of these fuels that can be fired. Fuels that are candidates for cost reduction are paper, sludge and subsidized fuels such as rice straw and other agricultural residues like almond shells. Paper and residues from paper recycling have recently been included in the list of biomass fuels eligible for subsidies and incentives.

### *Rice Straw*

Rice straw has been of particular interest to biomass plants since it was to receive a \$10 million subsidy. That subsidy has been reduced to \$2 million and its financial impact is in question.

Rice straw removal costs are approximately \$40/acre or \$20/ton (2.1 ton/acre) plus costs for storage, transportation and preprocessing. Despite subsidies and short-term incentives, rice straw will eventually reach an operational value that is determined by the price of other available fuels. Urban wood waste, orchard pruning and other woody fuels establish the value of fuels at approximately \$1/MMBtu, equal to \$14/ton rice straw at 14 MMBtu/ton (15% moisture content, 19% ash). Alkali in the straw and other handling issues may create pressure to require that rice straw be delivered to a power plant for \$0.50/MMBtu, or \$7.50/ton. These prices are considerably lower than the costs for rice straw harvesting, storage and transportation which have been estimated at \$28-\$43/ton.

The primary limitation of using rice straw is its high content of alkali. Companies that produce commercial pyrolyzers and gasifiers avoid straw of all kinds, but especially rice straw, because of the problems with alkali deposits. Pyrolysis conditions help to concentrate alkali with the char, which is removed from the gases. However, enough alkali is still contained in the gas, even with low alkali straw, to cause problems in downstream processes such as catalytic reformers and combustion turbines.

California power plants are not generally designed to handle straw as a fuel. California biomass plant managers have made it clear that the amount of rice straw burned will depend on the alkali content of the fuel and the suitability of their boilers to accommodate it. Plants have very limited experience burning rice straw. The Wadham plant at Williams burned rice straw experimentally at commissioning and found that the alkali content was too high for acceptable burning in combination with rice hulls. Straw was also fired experimentally in 1989 at the Madera and El Nido bubbling fluidized bed plants in Amador County, but only the Imperial

Valley Resource Recovery Facility was designed to receive and prepare up to 50% straw as fuel at approximately 10 tons per hour. The system was abandoned in 1993 when it was determined that the boiler was not suitable for firing a high percentage of straw. Close-Coupled Gasification was one alternative to direct firing that was considered at that time.

Rice straw represents a cost and opportunity for California biomass-to-energy plants. Straw harvested and stored and delivered to a plant for \$30.00 with an additional \$5.00 for handling and processing will cost \$35/ton or \$0.035/kWh. CCG processing in a \$3.4 million gasifier would add \$0.0095/kWh (\$0.61/MMBtu) in capital and operating and maintenance costs for a cost of fuel gas of \$0.044/kWh equal to \$44/ton of rice straw. In order to meet a fuel gas target of \$1.00/MMBtu (\$0.015/kWh or \$15/ton at 18,526 Btu/kWh) a subsidy of \$.03/kWh would be required, corresponding to \$30/ton of rice straw. Even if rice straw could be gasified it is not likely that the rice producers will dispose of the straw at costs of \$30-\$40/ton.

### ***Non-Recyclable and Mixed Waste Paper***

Paper wastes from pulp mill processing and seasonal agricultural residues are all good candidates for CCG applications. In some areas residues from paper recycling can be obtained for a disposal fee of \$20/ton. This represents a subsidy of -\$0.02/kWh. The rejects from paper recycling, often called light rejects or old corrugated container rejects (OCCR) are wet and must sometimes be shredded for handling and blending into existing feed systems. OCC rejects constitute about one third of the scrap paper delivered to a recycle mill. They must be blended 4:1 with dry fuels to reduce moisture to 20% for gasification. OCCR can sometimes contain unacceptable levels of chlorine. Substantial incorporation of OCCR may require additional equipment to remove chlorine from the stack gas unless the plant is equipped with a dry scrubber for acid gas treatment. Mixed waste papers contain clays and other elements that help gasification and sometimes offset the effects of alkali or chlorine in the fuels. While some chlorine will be captured by other fuels and by reactions in a fluidized bed, acid gas cleanup may be required.

Mixed waste paper must be shredded and sized before blending with other fuels for gasification. The low density of shredded paper causes problems with feeding and consistent gasification in industrial-scale fluidized beds. Costs associated with the preparation and handling of non-recyclable and mixed waste paper will vary with the equipment at the biomass-to-energy plant. Some plants have auxiliary reclaim bins that could handle some portion of wet pulp mill

residues. Most biomass plants in California have open storage piles so that receiving urban fuels may require installation of buildings and equipment for fuel processing and storage. Light rejects can be delivered daily and require minimal storage. Residues are inert and present no environmental hazard except for wind-blown paper, similar to refuse-derived fuel. They do require wet bulk storage and reclaim into the fuel system. Light rejects are best-received, sized, screened and processed into one or two-day covered storage bins. Plants with disk screens and hammermills for oversized fuel may be able to receive and process light rejects with little additional investment. Light rejects, or OCCR, are most suited to moving grate reactors with good ash removal systems since they contain significant quantities of wire and staples that are not easily removed by magnets. Wire tends to accumulate in fluidized beds.

Mixed waste paper is often received in compacted bales from waste generators or material recovery facilities (MRF). The paper must be de-baled and shredded before feeding to gasifiers or boilers. Light shredded paper is often blended with dense woody fuels to provide a uniform flow of fuel to a gasifier or boiler. Shredding and sizing equipment for mixed waste paper is different than most equipment at California biomass plants. Plants would have to invest in de-balers or shear shredders, screening, metal separation and secondary shredding equipment similar to pelletized or cubed refuse-derived fuel (RDF) processes in a MRF. The cost of processing fuel in a MRF can vary from \$30-\$45/ton with installed capital costs of \$2-\$5 million to process 80,000 tons per year. One option for biomass plants is to buy RDF cubes from an MRF, typically at a cost of \$15/ton. In most cases, these could be direct-fired in a boiler without using a CCG. The MRF realizes the benefits of the tipping fee and sale of recoverable paper while the power plant obtains the fuel at “market” costs.

Riverside County and Orange County have considered co-location of gasifiers at Material Recovery Facilities. The study concluded that with a \$22/ton tipping fee, power could be generated for \$0.04/kWh.

Another alternative is to co-locate an MRF at an existing power plant. RDF gasifiers have operated for several years in Greve in Chianti, Italy where two 15 MW thermal CFB’s fuel a steam boiler and cement kiln using 200 tons of RDF per day. New plants are proposed in Greece. RDF gasification for “indirect” cofiring has been advocated for RDF in Finland. Future Energy Resources gasified RDF at their pilot facilities during the development of the dual-fueled

gasifier. And several gasifiers have demonstrated the benefits of gasification of refuse-derived fuels on NO<sub>x</sub> reduction including the 70 MW CFB at Lahti, Finland.

### *Other Agricultural Residues and Fuels*

The best potential fuels for Close-Coupled Gasification are probably the pits nuts and shells that are currently burned in biomass plants. Seasonally these agricultural residues can be obtained for as a little as \$2.00/ton or \$0.002/kWh. The residues are dense and easily handled in bulk. In most biomass plants they could be fed separately or easily diverted to a gasifier from the main fuel stream. Some plants are equipped with separate bulk metering bins for pits, nuts and shells. Use of pits, nuts and hulls has been limited in individual plants by the quantity that can be burned without problems of agglomeration, deposition or NO<sub>x</sub>. The potential for use of almond shells has been reported in this project. Title V permits limit the amount of almond hulls that can be burned to 5% at one plant. Other plants are not limited by specific fuels. However gasification could be used to increase the quantity of these fuels burned in existing plants.

At a 10% utilization rate a gasifier could be reduced in size to about 5 MWe or 5 dry tons per hour (40,000 tpy). At \$2/ton fuel costs are about \$0.15/MMBtu (\$0.0023/kWh). Capital costs at \$300/kW, or \$1.5 million, with O&M at 5% would add \$0.64/MMBtu (\$0.0095/kWh) for a levelized fuel gas cost of \$0.79/MMBtu/h, equal to a power cost of \$0.012/kWh.

Table 35. Status of biomass plants in California.

Status	Number of Plants	Generating Capacity (MWe)
Operating	26	550
Idled	17	217
Dismantled	14	97
Converted to Gas	5	111
TOTAL	62	975

Source: California Environmental Protection Agency, Integrated Solid Waste Management Board, 2001.

Table 36. Boiler type and capacity by PG&E and SCE contract July 2001.

Contract	No.	SS	SUS	CFB	FB	Fuel	MW
Cogen	1	1				Wood	6.5
Power	20	16		3	1	Wood	402.8
	1	1				Walnut	4.5
	1		1			Rice Hull	26.5
	1			1		Ag Waste	25.0
				1			47.0
Misc.	2						37.7
1990's contracts	60	45	1	7	10	(Various)	

Notes: SS = spreader stoker, SUS= suspension fired, CFB = circulating fluidized bed, FB = fluidized bed.  
Southern California Edison, Colmac Energy, G. Morris, 1997.

Table 37. Costs to produce electricity from biomass in California.

Biomass Fuel	% of Total Biomass Consumed (%)	Average Cost (\$/bdt)	Average Revenue (¢ /kWh)	Average Cost (¢ /kWh)	Net Difference (¢ /kWh)
Wood Processing Residues	39%	\$10-\$20	5.0	6.6	(1.6)
In-Forest Residues	19%	\$25-\$30	5.0	7.4	(2.4)
Agricultural Residues	17%	\$0-\$15	5.0	6.5	(1.5)
Urban Wood Residues	25%	\$0-\$20	5.0	6.2	(1.2)

Source: Adapted from IWMB, 2001 Table B. Fuel costs from GE EER survey.

Table 38. NO<sub>x</sub> Emissions limits in California biomass plants.

NO <sub>x</sub> (lb/MMBtu)	No.	MW	Fuel
.28	1	20	Wood
.20	1	5	Walnut
.10-.15	12	7 - 50	Wood
.08	2	25-36	Ag
.05-.063	2	18.5	Wood
.023	1	18.3	Wood
Uncontrolled:			
.49 (.187-.863)	8	AP-42(4.5)	Dry wood
.22 (.023-1.281)	82	AP-42-(4.5)	Bark, wet wood

### **3.10 Production Readiness**

The purpose of the production readiness plan is to outline the potential commercialization of CCG in the California biomass power industry and develop a plan for implementation. In this project, the GE EER team has pursued a strategy of commercialization through a consortium of strategic partners including fuel suppliers, biomass power plant owners and operators, and gasification system suppliers. The consortium has guided the testing and verification of the technology and has continually assessed the feasibility of applications. Markets and applications were studied. Potential partners for commercialization have been identified. The capability of potential partners to implement the technology has been assessed. Risks for development have been identified and development needs have been determined. A plan for implementation of the technology includes consideration of the commercializing partners, market impact and benefits, identification of a base case for implementation, and a development plan.

The objectives of the production readiness plan are to:

- Identify potential commercialization partners.
- Determine technology development requirements for commercialization.
- Determine steps for implementation.
- Assess market, financial and investment requirements for commercialization.

#### **3.10.1 Commercialization**

The GE EER team concluded that CCG could result in a near term commercial process. The project has assessed production readiness through the development process in a variety of ways. Potential commercial biomass plants that could implement the technology were involved in the study. Gasification technology providers also participated. Some suppliers, with similar but proprietary technologies, declined to participate but are interested in the results. Other suppliers that are interested in the process have been interviewed to determine their commitment toward commercialization.

#### ***GE NO<sub>x</sub> Reduction Technologies***

Once demonstrated, GE expects to lead commercialization of CCG systems as an engineering and construction company that provides turnkey installations. CCG is similar to the NO<sub>x</sub> reduction, re-burn and advanced re-burn technologies that GE already supplies to industry.

GE will design and supply the CCG system and collaborate with gasifier and fuel handling system suppliers for the balance of the CCG system. In this project The GE EER team assessed the potential for NO<sub>x</sub> reduction using CCG at the 50 MW Wheelabrator Shasta plant, the 30 MW Wadham Energy Plant and the 30 MW Woodland Biomass plant and found the solutions to be within their capabilities.

As the lead engineering firm, GE would collaborate with others to establish a first industrial or pilot facility. At the present time, no California plants have gasifiers. The GE Irvine team has been working with suppliers and with biomass plants to locate a pilot facility to verify the CCG technology at the industrial scale.

### ***Commercialization Partners***

The major components of CCG are: fuel preparation system, gasifier, gas cleanup (as necessary), gas delivery, burner (or mixing device at the boiler), and controls. There are approximately ten companies in the United States who provide improved combustion air or NO<sub>x</sub> reduction systems to the biomass industry. Some are interested in the technology but they are not likely to develop CCG since it depends on installing a gasifier. Companies that supply low Btu gas burners for producer gas are less likely to supply CCG systems. Most of these companies, like Forney Corporation, John Zink/Todd Combustion, Callidus Technologies, and Coen Company are primarily interested in burner sales.

Several companies offer systems for fuel preparation and gasification. Gasifier and boiler suppliers are most likely to develop CCG systems commercially. Many gasifier suppliers also supply boilers or have commercial license arrangements with boiler suppliers to build and supply their equipment. The GE EER team has contacted gasifier and boiler suppliers to assess their interest in commercializing the CCG process.

### ***Gasifier Suppliers***

A preliminary analysis was conducted of the ability of potential partners to implement the CCG technology. All of the contacted gasifier suppliers are interested in commercializing CCG since it enhances the value of their systems. The principal suppliers are shown in Table 39. In a worldwide database of 468 gasifiers in 163 commercial projects that is maintained by NETL, approximately 16 are shown to be producing syngas or electricity from biomass and wastes. Some of these plants have been supplied by the companies in Table 39. Others have supplied

gasifiers for smaller scale industrial uses but in capacities suitable for co-firing or CCG in California biomass or coal plants.

A principal motivation for gasifier suppliers to be interested in CCG is that NO<sub>x</sub> reduction offers an added benefit when gasification is used for co-firing. NO<sub>x</sub> reduction benefits motivated other gasification projects such as a 56 MWe Gas Technology Institute (GTI) project with Boise Cascade Corporation. GTI has implemented successful methane de-NO<sub>x</sub> systems with Boise Cascade and offers gasification as a potential solution. Foster Wheeler Corporation sees re-burning as an enhancement of the NO<sub>x</sub> reduction they have experienced in simple co-firing of biomass with coal at the LAHTI facility in Finland and the Electrabel gasification facility in Belgium. Foster Wheeler has studied the potential of co-firing straw via gasification. They now have four industrial biomass gasifiers in operation. Zeltweg in Austria also demonstrated co-firing and reported on the benefits of NO<sub>x</sub> reduction. Lurgi sees the potential benefits based on their four industrial gasification systems. Companies with gasification systems firing other fuels that have quoted co-firing systems but as yet have not built CCG facilities are also interested in NO<sub>x</sub> reduction from CCG. These include Heuristic Engineering, Primenergy and several smaller scale gasifier suppliers.

Two suppliers that have been involved in the CCG project are Future Energy Resources (FERCO) and Energy Products of Idaho (EPI). FERCO has been successful at co-firing biomass gas with wood at the 50 MWe McNeil station in Vermont. They are interested in demonstrating potential NO<sub>x</sub> reduction benefits from co-firing for this and other applications. EPI has experience in building gasifiers and has promoted CCG with biomass co-firing.

### *Other Potential Stakeholders*

Biomass plant owners and operators are important stakeholders in the CCG process. Three biomass plants have participated in the project. Their interest is clearly to use CCG as a means of incorporating low cost, subsidized or troublesome fuels while reducing the consumption of ammonia or urea in their SNCR systems. Fuel specific plants like Wadham Energy need CCG to incorporate other biomass fuels which in their case is limited to finely divided, dry rice hulls or wood waste. Plant with circulating fluidized beds, like Woodland Biomass, and spreader stokers, like Wheelabrator, could use CCG to gasify troublesome fuels in a separate reactor. The primary interests of the biomass plant is a net reduction in the cost of fuel

so they can remain competitive and simultaneously reduce NO<sub>x</sub> emissions, which would result in a reduction of their SNCR costs.

Other potential stakeholders in CCG technology are the waste disposal or waste reduction community. The portion of the waste stream that is not classified as municipal waste but can be reduced by gasification and fired in boilers for power generation is significant. There are emerging corporate incentives, such as ISO 14001, to recover the energy in non-recyclable wastes via power generation rather than disposing of them in a landfill. Companies are willing to pay a tipping fee to dispose of wastes, which improves the economics of the CCG process. This is estimated at half the commercial landfill cost or approximately \$30/ton of waste. Partners in CCG commercialization would be waste generators seeking disposal alternatives, waste haulers seeking new markets or more economic routes, or municipalities seeking to achieve recycling goals. While the California Integrated Waste Management Board (IWMB) has been interested in waste gasification no individual stakeholders representing the waste community have been identified in this project.

Gasification is a means of changing the form of the industrial paper, demolition or other waste so that it can be fired in stand-alone or existing boilers. Waste gasification systems are used in this manner in Iowa, Finland, Belgium, Germany and Holland. Mixed wastes including sewage sludge are also gasified by Lurgi and burned in a cement kiln in Germany. TPS gasifies refuse-derived fuel at a cement plant in Italy. The capacity of these plants is equal to 6 MWe to 20 MWe. Partners will emerge as costs to dispose of non-recyclable wastes increase in California.

Companies that are not likely to be stakeholders in diverting wastes to power plants are those that benefit from disposing of wastes in landfills. An example of this is a trend toward diversion of urban wood wastes from biomass plants to landfills. Landfill operators reportedly process the wood wastes for use as alternate daily cover (ADC). The stocks of ADC however are reported to exceed the needs of the landfills.

### ***Capacity and Financial Stability of Commercial Partners***

The economic climate for energy in California affects the potential for commercialization of the CCG technology. Markets for biomass power and for disposal of biomass residues are uncertain and subject to changes in regulation. The market for the technology has changed in the course of the study. At the beginning of the project, California provided subsidies for the

disposal of agricultural residues such as prunings and straws. During development and testing there was an energy crisis in which plants that could expand capacity benefited from high prices. These favorable markets and subsidies have subsided. There is currently a low demand for biomass energy. Factors that would make the general market conditions improve include:

- Incentives for disposal of biomass residues in energy plants.
- Incentives or regulations for coal facilities to co-fire biomass.
- Increased NO<sub>x</sub> regulation for existing biomass plants such as the industrial MACT.
- Incentives to install gasifiers, such as the producer gas tax credit.

Several companies are capable of commercializing a CCG system in spite of the market instability in the biomass energy industry. CCG gasification for NO<sub>x</sub> reduction and co-firing remains a long-term solution for waste reduction in California that can be incorporated in new plants or retrofit to existing plants.

The most recent commercial biomass gasifiers in North America were installed in 1998. That was the last year to qualify for the producer tax credits available for federal tax relief. There is currently one commercial gasifier in operation and two others that are planned or in construction. The two planned systems are demonstration systems for the pulp and paper industry, which depend on public funding for their completion. Gasification system suppliers compete on the world market and some suppliers have installed commercial boilers or gasifiers in Europe or China. Others have built industrial scale demonstration systems.

The two companies that have participated in the CCG project, Energy Products of Idaho (EPI) and Future Energy Resources Company (FERCO), continue to actively promote biomass gasification. EPI is an energy system supplier with more than 80 boiler and gasifier systems installed. EPI's experience with biomass gasification includes gasifiers in California, Tennessee and Iowa. An EPI wood fired gasifier at the State printing office in Sacramento was one of the first industrial gasifiers in North America. A 6 MWe Iowa facility is gasifying industrial and agricultural processing residues. The gas is fired in a boiler. The plants predecessor in Oregon operated from 1986-1992. The current system has been in operation since 1998. A wood fired gasifier in Tennessee of the same capacity was installed in 1998. EPI has supplied bubbling fluidized bed combustors and boilers in North America and abroad since 1976. They built several biomass combustion facilities in California. The boiler and combustor business provides financial stability and attests to the fact that EPI could supply a CCG system. EPI studied the

feasibility for a CCG system for Wadham Energy. They have actively promoted co-firing biomass using gasification in industry and research forums. Have carried out detailed studies on coal facilities in Arizona and North Carolina for using biomass via gasification to co-fire or refuel aging coal facilities. EPI has acquired the rights to a fluidized bed technology from Iowa State University for the practical cleaning of hot gas so that unwanted pollutants can be removed from the gas stream before gasification. Their continued development of gasification as an alternative shows their commitment to CCG commercialization.

FERCO is a technology development company formed to commercially supply the dual fluidized bed gasifier developed by Battelle Columbus Laboratories to industry. The principle project was the installation of the FERCO Silvagas plant at the 50 MW McNeil station in Burlington, Vermont. The project took the gasifier from pilot operation to commercial scale operation including extended testing for gas cleanup and other gasification systems. Gasifier operation has been suspended while the company pursues commercial projects but will be reactivated in the future and is available for CCG scale up tests. FERCO is currently involved in developing industrial gasifiers at two locations. They have also developed a license for their technology.

### **3.10.2 Implementation Plan**

The implementation plan for the CCG technology differs from a manufacturing plan because the major components of the technology are already commercially available. Critical production processes, equipment, facilities, manpower and support systems already exist to produce a commercially viable product. The critical production processes that are needed for CCG are identified in the base cases considered in the market and economic assessment. There are no capacity constraints for production since the size of the gasification system required is smaller than systems used in most existing biomass plants. The principle challenges for commercialization are the demonstration at the industrial scale, mitigation of risks and appropriate market circumstances.

#### ***Process Development and Demonstration***

Test results from the pilot facility at GE's Irvine test site demonstrate that the CCG can reduce NO<sub>x</sub> within sufficient safety margins. The estimated yield and gases have been shown to be compatible with the cost and quality requirements of the biomass plants. However, an

industrial scale demonstration is needed before CCG will be accepted by the industry. An industrial demonstration must be of sufficient capacity to convince industry that the technology can solve common fuel handling, scale up and operational concerns. CCG technology must be operated in an industrial environment to be accepted.

The capacity and operation of technology verification at the industrial scale must be credible to industry. It must have sufficient capacity, yet it must be small enough so that if special or different fuels are used then the quantity of fuel should be obtainable in the current market. Biomass plants participating in the project have indicated that 35 tons per day or 10,000 tons per year of a special fuel is available in the market place. That would indicate a nominal gasifier capacity of 2 tons per hour. The gasification plant would produce 25 MMBtu/h or 1.4 MWe. At 10% fuel gas input this would supply a 10 MW power plant. We estimated the cost of the plant to be \$1.5 million or \$1,076/kWe.

An alternative to building a new facility for demonstration would be the use of an existing biomass plant with a gasifier configured for co-firing. The FERCO demonstration gasifier at the 50 MWe McNeil Station in Burlington, Vermont has the capacity to gasify 350 tons per day of fuel to produce 40 MWth or 10 MWe, which is 20% of the rated capacity of the power plant. The facility has the fuels, capacity and operational history to be credible to the biomass industry. The facility could be prepared and operated for about four months for the cost of building a new 1.4 MWe gasifier. These are two credible possibilities for scale up and demonstration toward commercialization to be considered in a Phase II proposed demonstration.

### ***Risks and Success Factors***

Full-scale demonstration of CCG should clear away the principle risks associated with the new technology. Biomass plant operators need to see a demonstration of the intended NO<sub>x</sub> reduction. The plant must be acceptable from an operational point of view since it is another device that constitutes a second management problem. Manpower and labor issues must be demonstrated within acceptable limits. Operational health and safety issue must also be addressed. A concern of current SNCR systems is the hazard of ammonia storage and handling.

Finally the costs of the feedstock and the practical benefits of CCG in operation must be demonstrated. The biomass industry has shown an aversion to new systems since the start up costs for biomass industry was slow and costly from 1970s to present. Successful demonstration of these factors will mitigate fears about adopting anew technology.

Factors that contribute to successful commercialization are primarily markets for biomass power, waste disposal and regulations. An increase in demand for biomass power alone is not a success factor for CCG since CCG gasification displaces the capacity of an existing biomass plant rather than adds to it. However it does provide a means for biomass capacity to be increased in the eight coal fired utilities in California. Improved markets for biomass power would also increase demand on fuels increasing the value of plants that are able to process lower quality fuels. Economic pressure to dispose of solid wastes will also increase the chance of success for CCG by increasing the costs of fuel. Regulations for increased biomass production, as through a renewable portfolio standard, or for increased NO<sub>x</sub> compliance, will also increase the opportunities for CCG commercialization.

### ***Financial and Investment Issues***

Gasifiers are large, capital equipment items that will generally be shop fabricated as modules and field assembled with rigging. Except for the reactor, none of the parts and subsystems are custom fabricated and are substantially vendor supplied, catalog items. Therefore, no substantial capital investment is required for manufacturing. Fabrication shops will initially be used for the structural steel and electrical controls. Gasifier suppliers and commercial fabrication shops will initially be used for these components.

The major initial GE investment in marketing and engineering design of standardized gasifier sized should be in the order for \$100,000 to expand the current design data to 50 to 300 tpd gasifier plants. Biomass IPP marketing has flowed from this development program. Several plants have been consulted about the NO<sub>x</sub> control and increased renewable or co-firing. The results of the project have been presented at several biomass forums.

### **3.10.3 Conclusions**

The CCG technology will be ready for commercialization once it has been demonstrated on the industrial scale. Potential commercialization partners are prepared and promoting the technology in anticipation of demonstration. Market or regulatory drivers must be in place for the first commercial implementation for CCG. GE EER's Irvine team and gasification system suppliers are anxious to move to Phase II to demonstrate the CCG technology and pave the path for its commercialization.

Table 39. Commercial gasifier suppliers.		
<i>Supplier</i>	<i>Gasifiers</i>	<i>Boilers</i>
Carbona	Yes	No
Future Energy Resources Company (FERCO)	Yes	No
Gas Technology Institute (GTI)	<b>YES</b>	No
Heuristic Engineering	Yes	No
MTCI/Thermochem	Yes	No
Primenergy, Inc.	Yes	No
Zeltweg	Yes	No
Bioneer	Yes	Yes
Energy Products of Idaho (EPI)	Yes	Yes
Foster Wheeler Corporation	Yes	Yes
Lurgi	Yes	Yes
TPS	Yes	Yes

## References

Extensive references for discussions presented in Sections 3.1 – 3.10 can be found in the detailed task reports of these sections. These reports were submitted to the California Energy Commission contract manager as part of the deliverables for this project.

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